Expert Report of Greg Karras
Communities for a Better Environment (CBE)
4 September 2013

Regarding the

Phillips 66 Company Propane Recovery Project
Draft Environmental Impact Report released in June 2013 by the
Contra Costa County Department of Conservation and Development
State Clearinghouse #2012072046
County File #LP12-2073

Contents

I, Greg Karras, declare and say:

1. I reside in unincorporated Marin County and am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial health and safety investigation, pollution prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

Qualifications

2. My qualifications for this opinion include extensive experience, knowledge, and expertise gained from nearly 30 years of industrial and environmental health and safety investigation in the energy manufacturing sector, including petroleum refining, and in particular, refineries in the San Francisco Bay Area.

3. Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from refineries, to assess environmental health and safety impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I served as an expert for CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives.

I served as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the Chevron Richmond refinery "Hydrogen Renewal Project" now subject to reanalysis pursuant to a California Court of Appeals Order,[1] and the "Contra Costa Pipeline Project" now pending before the County.[2] I serve as an expert for CBE in collaboration with labor, academic, and other community based and environmental groups in a project involving comprehensive investigation of environmental health and safety impacts of, and alternatives to, refining denser, more contaminated types of crude oils.

4. I authored a technical paper on the first publicly verified pollution prevention audit of a California petroleum refinery in 1989 and the first comprehensive analysis of refinery selenium discharge trends in 1994. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. From 1992–1994 I authored a series of technical analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts.

5. My recent publications include the first peer reviewed estimate of combustion emissions from refining denser, more contaminated "lower quality" crude oils based on data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010, and a follow up study that extended this work with a focus on California and Bay Area refineries, which was peer reviewed and published by the Union of Concerned Scientists in 2011. Most recently, I presented invited testimony on *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's public hearing on the Chevron Richmond refinery fire that was held on 19 April 2012. My curriculum vitae and list of publications are attached hereto.

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[1] <u>See</u> *CBE v. City of Richmond* 184 Cal_App.4th.
[2] <u>See</u> Contra Costa Pipeline Project file, County File #LP072009, SCH #2007062007.

Scope of Review

6. In my role at CBE I have reviewed the proposed project called the Phillips 66 Company Propane Recovery Project (project) and the June 2013 Draft Environmental Impact Report (DEIR) released by Contra Costa County for public review of the proposed project. My review of the project and DEIR reported herein is focused on catastrophic incident, flaring, air emission, cooling system, and climate impacts that could result from the project. My opinions on these matters and the basis for these opinions are stated in this report.

Project Description

7. According to the DEIR, the project would install, at the Phillips 66 San Francisco Refinery (SFR) Rodeo facility, process equipment that would enable the refinery to treat, recover, store, and ship for sale 8,000 barrels[3] of additional liquefied petroleum gases (LPG) daily, including 4,200 b/d of propane and 3,800 b/d of additional[4] butane. This equipment would include:

- a three-reactor hydrotreater installed to the coker and related fuel gas treatment;
- three 120–140 foot tall fractionator towers and two 70 foot tall absorber towers;
- 140 MMBtu[5] per hour of expanded steam boiler capacity to heat this processing;
- six pressurized propane storage tanks totaling 15,000 barrels capacity; and
- two additional rail spurs and a two-sided loading rack to load eight rail cars/day.[6]

8. Ancillary equipment such as additional process vessels, heat exchangers, pumps, and piping would be installed, and modifications to an existing once-through system would increase Bay water use to 40,000 gallons/minute to cool the new processing.[6]

9. Information that is needed to understand and evaluate the environmental implications of this project has, in many cases, been omitted from the DEIR, even though the same information that the DEIR omits is publicly available from other sources. Some forty of these critically important deficiencies in the DEIR's description of the project are discussed in paragraphs 10 through 47.

[3] 1 barrel (b): 42 gallons; 0.159 cubic meter (m^3). Conversely, 1 m^3: 6.29 barrels; 264 gallons.
[4] The refinery already produces 5,500 b/d of butane for sale, based on the DEIR at 3-21.
[5] MMBtu: 1 million Btu (British thermal units); 1.00551 gigajoule (GJ).
[6] See DEIR at 3-21, Table 3-2, 3-27.

10. The DEIR does not disclose how long the project could be expected to operate. The omission is important because the time frame of the project must be identified to understand and evaluate potential impacts of project operation over that time.

11. There is no good reason why the time over which the project may reasonably be expected to operate should be kept secret in the DEIR. An operating life estimate must have been made to support critical equipment design specifications, such as vessel wall thickness and materials of construction to resist corrosion, and schedules for major maintenance "turnarounds." Phillips 66 also would have used this estimate in financial analysis before committing to the project. Publicly reported data show similar refinery processes have operated for 30–50 years or more.[7] Another EIR for a proposed project at the Richmond refinery suggested it is "reasonable to use past history as a guideline" and to expect similar "equipment to be operated for several decades."[8] Moreover, an EIR for a related project at this refinery disclosed and analyzed a 40 year project duration.[9]

12. Impacts of the project that would emerge later and are obscured by this omission include those from its effects on a concurrent feedstock switch. California refiners' long-stable and dominant sources of crude oil are dwindling, driving an historic refinery crude switch. See Chart 1. Foreign crude was only 6% of total California refinery crude feed in 1990; in 2012 it was 51%.[10] By 2020, roughly three-quarters of the crude refined statewide likely will *not* be from currently producing sources in California or Alaska.[11] Because it relies on dwindling California oil supplies via pipeline for most of its crude feed,[12] the SFR almost certainly will be among those California refineries that switch crudes dramatically during the project's operating life. Indeed, the refinery's 1995 wharf project forecast this outcome,[9] and its recent related project to allow 67% more crude delivered via its wharf[13] would begin to implement the switch. Among other problems, omitting the operating life of the project obscures the project's implications for the choice of new crudes, and the impacts of that feedstock choice.

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[7] See BAAQMD, 2009; and BAAQMD, 2011.
[8] See City of Richmond, 2008. SCH #2005072117, FEIR Response to Comments, page 3.16a-1.
[9] FEIR SCH #91053082 (State Lands, 1995). See section 4 at pages S-1 (stating a 40-year project duration) and S-4 ("it is assumed that sources of San Joaquin" and "Alaskan crude, will decline" and "[m]ore reliance will be placed on crude imports from foreign sources").
[10] Cal. Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).
[11] See Baker & O'Brien, 2007; and Croft, 2009.
[12] Based on *Oil & Gas Journal* capacity and 11.2–18.7 MMb/y wharf limit.
[13] Based on 11.2 vs 18.7 MMb/yr (DEIR at 5-4); see also ERM & BAAQMD, 2012.

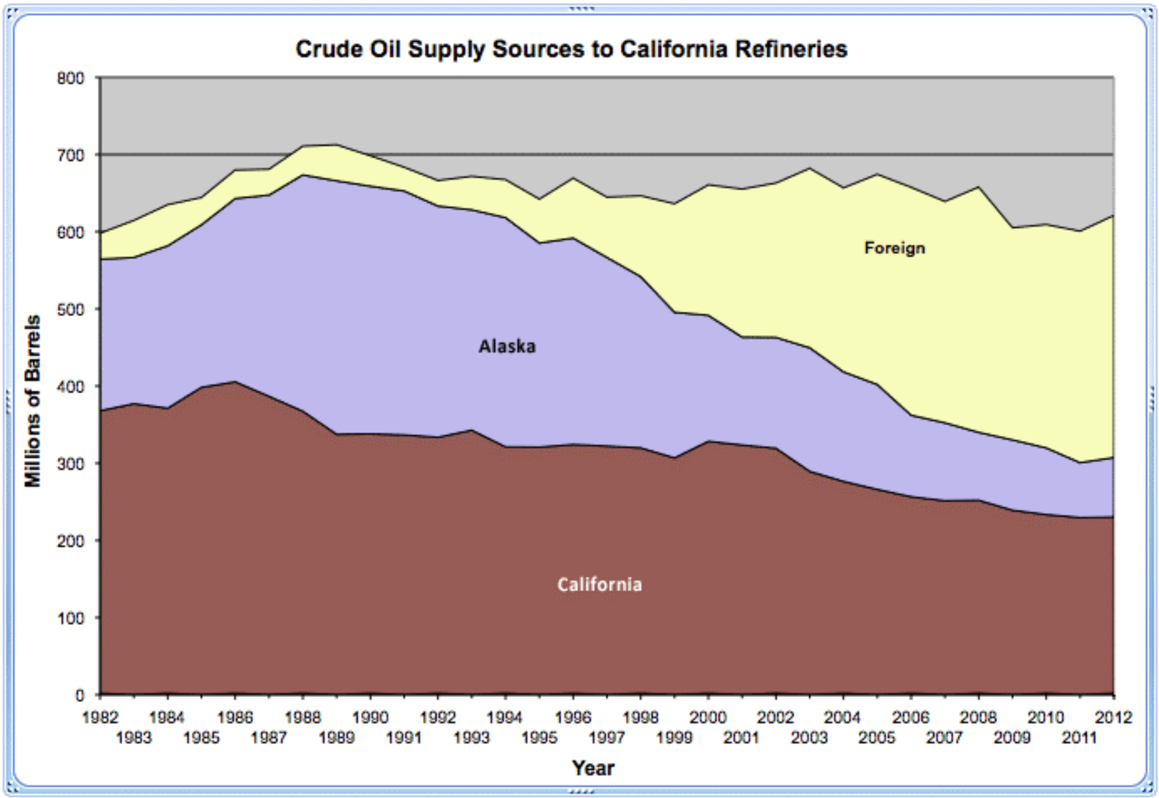

Chart 1. Crude oil supply sources to California refineries, 1982–2012
California Energy Commission (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts).

13. The DEIR does not report the crude oil quantity processed by the refinery. Its crude throughput (≈120,000 b/d[14]) must be known to understand and evaluate the scale of environmental impacts resulting from project effects on crude processing.

14. The DEIR does not disclose the changes in crude oil use that could result from the project. Data summarized in Table 1 suggests that meeting project objectives would increase the refinery's total LPG production for export sales to 11.2% of its total crude feed volume, 230–570% of the butane yield from initial distillation of its total crude feed, and 450–1,200% of the propane yield from distilling that crude.[15] This change in

[14] San Francisco Refinery (SFR) crude capacity in b/cd; volume that can be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime (*Oil & Gas Journal,* 2012). This value is close to those the company reported to air and water officials (see Phillips, 2012b; SFR NPDES permit orders).
[15] See data in Table 1. LPG production from DEIR at 3-21. Total post-project butane export is included because project equipment would replace existing processing for production of butane that is now exported and would not change existing crude distillation equipment to change LPG yield from crude distillation. See also EIA Refinery Yield: Monthly average U.S. refinery LPG yield ranged from 1.8–5.7% on crude volume during January 1993–May 2013.

processing would affect refinery production and create environmental impacts in several ways the DEIR does not describe:

- The location of emissions from LPG combustion would change. LPG now used as refinery fuel that is self-produced from crude would be removed from refinery fuel gas and sold for uses involving combustion at a different location.
- Fuel gas heat content would decline, as more LPG is removed from fuel gas and replaced with natural gas, which has a lower heat content. This could affect combustion sources, fuel gas balance, and flare gas recovery refinery wide. Effects from this fuel gas quality problem are different from, and could occur regardless of, the fuel gas quality improvement from sulfur removal that the DEIR describes.
- The refinery would become more reliant on severe processing of the denser oils in the crude stream in order to create enough byproduct gases from "cracking" these oils to fill the LPG gap between its crude distillation yield and LPG production objectives. This would be necessary to meet project export objectives because the refinery could not otherwise create enough propane and butane, and further would be driven by the enlarged revenue and profit streams from meeting those objectives.

Table 1. Post-project LPG production greatly exceeds refinery crude distillation yield

	Initial crude distillation yield[a]		Post-project LPG production[b]	
	% vol. on crude	barrels/day[c]	barrels/day	% of crude feed[c]
Propane	0.30–0.78	360–936	4,200	3.50
Butanes	1.35–3.31	1,620–3,970	9,300	7.75

(a) Median and 95th Percentile yields from 205 publicly reported crude oil assays (see Crude Assays).
(b) Total post-project production for export sales based on capacity reported (DEIR at 3-21).
(c) Calculated based on reported crude capacity of 120,000 b/cd from *Oil & Gas Journal* (2012).

15. The DEIR does not disclose the change in crude feed quality that could result from the project. The configuration of this project and refinery requires coking for the additional LPG-rich byproduct gases to meet the project's production and profit goals. Installing a catalytic cracker[16] or repurposing a hydrocracker would entail capital or lost motor vehicle fuels production costs that make those options conflict with maximizing LPG export profits. The U200 delayed coker is the primary source of LPG-rich gases that cannot be treated adequately by DGA (amine) processing; the project would "[i]nstall to U200" hydrotreating to provide this treatment; and the new hydrotreater's proposed purpose in this project is to allow LPG to be recovered from coker gases.[17]

[16] The Phillips 66 SFR does not include a catalytic cracking process. See BAAQMD, 2013.
[17] Phillips, 2012b at 4; DEIR at 3-5, 3-12, 3-16, 3-21, 3-23/24/25, 6-4/5; Phillips, 2012a at 5.

Delayed coking is severe thermal cracking (415–515 ºC at 15–90 psi for ≈24 hours) that is used to crack the densest oil streams processed, such as the residue from vacuum distillation of atmospheric distillation bottoms and bitumen.[18] Thus, the project would commit the refinery to continued coking of the highest-density part of the crude resource.

16. Importantly, denser coker feeds produce more gases and more LPG. Coking converts dense components of crude into oil streams that can be processed further to make light liquid fuels.[18] Named for its petroleum coke byproduct, it also creates byproduct gases with 1–4 carbon atoms (C4–), including butanes (C4) and propane (C3), which are burned as refinery fuel or, especially in the case of C3 and C4, sold as LPG.[19] Along with temperature, pressure, and reaction time, key process variables include feedstock properties and product targets.[20] Data summarized in Table 2 suggest that even at full coker capacity,[21] producing 8,000 b/d of LPG from refinery coker gases could require running the densest vacuum residues. Though it shows estimates only for a few possible feeds, Table 2 illustrates how, by adding an LPG export objective to its coker output, the project will drive the refinery to coking higher density feeds.

Table 2. Denser feeds increase C4– (including LPG) yield from delayed coking

Vacuum resid feed			
cut point (ºC)	+482	+538	+538
density (kg/m^3)	952–981	1,013	1,044
sulfur content (% wt.)	0.50–0.60	3.40	5.30
C4– (including LPG) yield			
C4– yield (% vol.)	10–11	15	17
C4– yield at 47 kbpd coker capacity **(b/d)**	4,700–5,310	6,880	7,930

C4–: hydrocarbons with 4 carbons or less; LPG (butanes and propane) and lighter gases.
Data from tables 7.1-2 and 7.1-6 in Meyers, 1986. C4– overestimates LPG yield. Yield converted from mass to volume assuming all C4– is LPG with 539 kg/m^3 density, and 967 kg/m^3 density coke.

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[18] See Meyers, 1986; Speight, 1991. Heavy or aliphatics-rich synthetic crude oils (SCOs) derived from partially pre-processing tar sands bitumen or crude residua may be included in these coker feeds, and refiners have sometimes labeled such SCOs as "gas oils," but calling them gas oil in this context is misleading. The DEIR does not disclose the project's reliance on low-quality oils.
[19] Delayed coking byproducts also include mercaptans and olefins (Meyers, 1986), which the new hydrotreater would remove from coker gases (Phillips, 2012a). Mercaptans are highly odorous: the coker thus may be linked to the refinery's notorious odor problems. These coking byproduct contaminants appear to be the reason for the new hydtrotreater but are not named in the DEIR.
[20] See Meyers (1986) at 7-69. The DEIR does not disclose this project link to coker operation.
[21] 47,000 b/cd (*Oil & Gas Journal,* 2012).

17. Thus, the project's new commitment to coking denser oils in order to meet its LPG export sales objective would lock the refinery into a crude slate at least as dense as, and likely denser than, its current slate. It likely would be denser because making more LPG would drive the refinery toward coking higher-density vacuum resid and bitumen and also toward increasing coker feed rates.[22] This would make denser vacuum resids, bitumen, or both a larger share of the crude slate, driving the density of the crude slate up.[23] Worse, it would do so during a period when the refinery almost certainly must switch—and in fact is beginning to switch—to new sources for its crude supply, as discussed in paragraphs 11 and 12. The project would thereby lock the refinery into a new crude slate of lower quality than it need otherwise choose. The DEIR does not disclose this effect of the project.

18. Contamination of refinery feedstock would increase as a result of the project. Sulfur and other toxic trace elements concentrate in the densest components[24] of crude that the imperative to produce more coker LPG would make a larger portion of the refinery's crude slate. Imports likely to dominate the new slate in order to fill SFR coking capacity—39% of its total feed volume[25]—with vacuum resid feeds as dense as the high-LPG feed shown in Table 2 could boost sulfur content substantially. See Table 3. Regional trends also support this expectation. See Chart 2. Indeed, sulfur in the new slate could reach ≈3–4.5% wt. The DEIR omits crude quality data,[22] but the crude feed is not nearly that high in sulfur now.[26] Available information suggests that the current average Rodeo feedstock is ≈915–918 kg/m^3 in density and ≈1–1.5 wt. % sulfur.[27] The crude slate resulting from the project likely would be denser and far more contaminated.

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[22] A separate environmental review of increased throughput rates reports some of the crude feed data that the DEIR should and could have reported, and reveals the company's plans to increase throughput rates for at least some of its upstream processing (see SMF EIR 2012 Excerpts). The DEIR does not mention or disclose this other proposed project or environmental review.
[23] The density of a crude oil is proportional to the volume of higher molecular weight, higher boiling point, larger hydrocarbons in that crude oil. See Karras, 2010; Speight, 1991.
[24] Sulfur, as well as nickel and vanadium, among other toxic elements, concentrates in the vacuum residua component of crude and bitumen. See Speight, 1991; Karras, 2010.
[25] SFR's 47,000 b/d of coking is 39% of its 120,000 b/d crude capacity (*Oil & Gas J.* data).
[26] Compare UCS (2011), ERM & BAAQMD (2012), *Oil & Gas Journal,* SMF EIR (2012) and EIA Imports Analysis: the Alaskan, imported, and San Joaquin (weighted average pipeline component) streams that comprise about three-quarters of Rodeo's slate have a combined average sulfur content of ≈1 wt. %: an average of 3% sulfur in this *current* slate is not plausible.
[27] UCS, 2011; ERM & BAAQMD, 2012; SMF EIR 2012.

Table 3. Selected data for crude oils with dense (≥ 1,040 kg/m^3) vacuum residue yield comprising ≈30–39% of the whole crude oil's total volume.

	DOE avg.[a] for these crude oils	Eocene[b] Crude (Mid-East)	Crude oils containing bitumen from tar sands[c]			
			Access Western	Christina Dilbit Bld.	Surmont Heavy Bld	WCS*
Whole crude						
density (kg/m^3)	918	945	922	923	936	929
sulfur (wt. %)	2.98	4.57	3.94	3.80	2.99	3.51
TAN (mg KOH/g)	——	0.20	1.70	1.55	1.39	0.94
nickel (ppm wt.)	——	21	72	68	51	58
vanadium (ppm)	——	59	194	179	140	141
Vacuum residue						
volume (% crude)	34	34	36	36	29	37
density (kg/m^3)	1,060	1,070	1,062	1,059	1,061	1,054
sulfur (wt. %)	6.04	7.35	6.49	6.21	6.07	5.56
Vacuum Gas Oil & Residue combined						
volume (% crude)	53	68	61	60	56	63

*WCS: Western Canadian Select. (a) Data from the U.S. Dept. of Energy, Crude Oil Analysis Database: shown is the average of all data for crude oils with residue yields that are 30–39% of crude volume, and also denser than 1,040 kg/m^3 (n = 15). (b) Data from publicly reported assays of traded oils (Chevron, 2013). (c) Data from Canadian Crude Quality Monitoring Program. See Crude Assays; DOE COA 2013, attached).

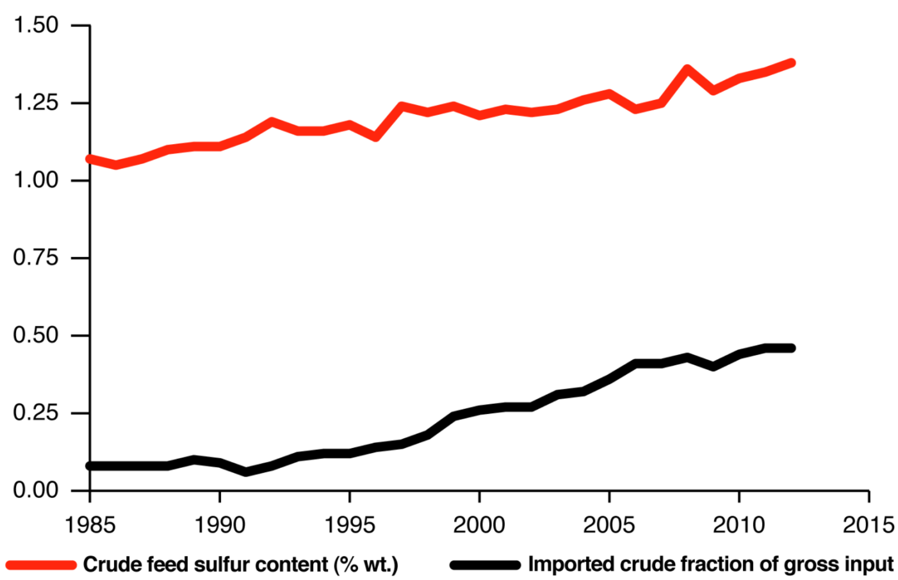

Chart 2. Sulfur and imports content of West Coast refinery crude feeds, 1985–2012
PADD 5 data from the U.S. Energy Information Administration (www.eia.gov/petroleum/data.cfm).

19. This new, dense crude slate likely will include more oil derived from "tar sands" bitumen. The project would commit the refinery to coker feed-rich crude over a period when the worldwide portion of high-density crude supplied by "heavy oil" and bitumen is likely to grow dramatically.[28] Bitumen has already come to dominate crude production in Canada,[29] the largest source of U.S. crude imports.[30] Moreover, crude can account for up to 90% of a refinery's operating costs,[31] and tar sands bitumen is price-discounted (due in part to delivery constraints),[32] so Phillips 66 is incented to run it, especially since the company's affiliates produce two of the bitumen blends shown in Table 3.[33] Indeed, recent major projects expanded the Rodeo facility's capacity to run more of these oils.[34] It now has vacuum distillation capacity to process a crude slate with atmospheric residua yield as high as 73% of the barrel, and coking capacity to process a slate with vacuum residua yield as high as 39% of the barrel,[35] which is more than enough to run the bitumen blends shown in Table 3.

20. Exactly what new crude blends to run is typically analyzed intensively based on many dozens of factors, but it is clear that the refinery will seek to run near capacity[36] and will continue to match blends of oils[37] to its processing capacities. Processing analysis for a blend of Western Canadian Select (WCS) and Alaskan North Slope (ANS) crude oils that the refinery could run is summarized as a hypothetical example in Table 4. In this simplified example, the refinery sells 12,000 b/d of the naphtha it distills from 120,000 b/d of WCS to other refiners, purchases 11,200 b/d of ANS gas oil, and runs its

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[28] See Meyer et al., 2007. *Heavy oil and natural bitumen resources in geologic basins of the world.* U.S. Geological Survey Open-File Report 2007–1084; see also Kerr, 2009.
[29] ERCB st 98–2009. *Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018.* Energy Resources Conservation Board, Calgary. See pp. 2–6; see also *Oil & Gas Journal,* 2007.
[30] EIA, 2013. (http://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbbl_a.htm).
[31] *Interim Investigation Report, Chevron Richmond Refinery Fire.* U.S. Chemical Safety and Hazard Investigation Board. Adopted 19 April 2013. (CSB, 2013.) See page 33.
[32] See Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)
[33] See Canadian Crude Monitoring Program (www.crudemonitor.ca): Christina Dilbit Blend ("produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility"); and Surmont Heavy Blend (50% owned, and operated by, Conoco Phillips Canada).
[34] See Strategic Modernization SCH #2002122017; Clean Fuels Expansion SCH #200509028; Marine Terminal Offload Project (ERM & BAAQMD, 2012); and DEIR at 3-19/20, 5-4/5-7.
[35] Based on process vs. crude capacities reported as of 1/1/13 by *Oil & Gas Journal* (2012).
[36] U.S. refineries ran at 90% of capacity on average since 1990 (www.eia.gov/petroleum/data).
[37] In addition to California and Alaska, the SFR processed oils from Canada and 20 other countries during 2004–2012 (EIA Imports Analysis).

Table 4. Example SFR refinery crude slate blending tar sands and conventional oils.

Crude slate	Volume (b/d)	Density (kg/m^3)	Sulfur (wt. %)	*Oil source*
Total input processed*	119,184	952	3.40	
Naphtha (naph)	11,088	691	0.05	*Western Canadian Select (WCS)*
Distillate (dist)	21,096	880	1.22	*WCS*
Vacuum gas oil (gas oil)	31,188	954	2.97	*WCS*
Imported vacuum gas oil	11,184	929	1.20	*Alaskan North Slope (ANS)*
Vacuum residua (resid)	44,628	1,054	5.56	*WCS*

** Excludes straight run (SR; from atm. distillation) naphtha exported (12,000 b/d).*

	Capacity (b/d)	Throughputs(b/d)					
Atmospheric distillation	120,000	WCS oils	108,000				
Vacuum distillation (VDU)	87,000	SR resid	44,628	SR gas oil*	42,372		
Delayed coking (DCU)	47,000	VDU resid	44,628	VDU gas oil	2,372		
Hydrocracking (HCU)	58,000	VDU gas oil	40,000	DCU gas oil	14,423	SR dist	3,577
distillate Hydrotreating	44,000	HCU dist	26,481	SR dist	17,519		
naphtha Hydrotreating	29,000	DCU naph	11,470	SR naph	11,088	HCU naph	6,442
Reforming	31,000	DCU naph	4,470	SR naph	11,088	HCU naph	15,442
Isomerization	9,000	DCU naph	7,000	HCU naph	2,000		

** Includes ANS oil that bypasses atm. distillation (11,184 b/d).*

Sulfur balance: 613 tonnes/day enter refinery in crude
–145 t/d leaving refinery in coke
468 t/d recovered (82% of SRU capacity)

Crude quality data from Canadian Crude Quality Monitoring Program (www.crudemonitor.ca) and publicly reported assays for ANS crude (*Oil & Gas Journal;* ExxonMobil and BP web sites). Refinery process capacities as of 1 January 2013 from *Oil & Gas Journal* (2012). Delayed coking yield based on typical yield reported for dense (1,044 kg/m^3) vacuum residua feed (see Tables 7.1-2 and 7.1-6 in Myers, 1986) and typical North American petroleum coke density (see Table S5 in Karras, 2010). Internal refinery hydrocarbon flow volumes may vary with varying volume expansion/loss effects in conversion processing. Capacities shown include the company's Santa Maria operations, which are integrated with the Rodeo operations via transfers of intermediate products, facilitating import/export logistics for refinery input blending.

vacuum distillation, coking, hydroprocessing, reforming and isomerization units at full capacity on the resultant WCS/ANS blend. This hypothetical example assumes WCS delivery, and represents but one of perhaps thousands of blends that the company might analyze closely for feedstock performance and cost containment. Nevertheless, this example shows that a new tar sands-derived crude slate could be very dense (≈952 kg/m^3) and high in sulfur (≈3.4 wt. %).

21. Crucially, logistical costs of bringing tar sands oil into the refinery—while rail loading, pipeline, and pipeline-to-boat capacities remain bottlenecked[38]—emerge as a

[38] See Fox, 2013; and Goodman, 2013. (NRDC expert reports on Valero Crude by Rail Project.)

barrier to processing much more tar sands oil at the San Francisco Refinery. By linking a major new profit stream from LPG sales to price-discounted coker feeds such as bitumen, while expanding total rail and wharf loading capacity, the project could breach this transport cost barrier, and increase tar sands crude inputs to the refinery.

22. A Phillips 66 web page presents a map depicting crude transport routes from the tar sands region of Canada to its SFR by rail, pipeline, and ship, and quotes Chairman and CEO Greg Garland among the following excerpted statements:

> "Advantaged crude sells at a discount relative to crude oils tied to the global benchmark … [and] include[s] heavy crude from Canada …
>
> 'We are looking at pipe, rail, truck, barge and ship—just about any way we can get advantaged crude to the front end of the refineries,' said Garland. …
>
> The next challenge for the company is identifying strategies to get more advantaged crude oil to its California refineries [which can run a wide range of crudes]."[39]

Separately, Garland disclosed that the company's "opportunity to improve performance in California is really around getting advantage crudes to the front end of the California refineries, its rail, its ship, it's *working on optimization of the cost structure and the export capabilities of those refineries.*"[40] (Emphasis added.) These disclosures support the evidence discussed in paragraphs 12–21 and shed some light on how expanding rail capacity, production capacity, and LPG sales revenue in a way that is locked into low-quality crude feeds could "optimize the cost structure" for getting cheap tar sands oil to the refinery. The DEIR omits these disclosures.

23. Among other problems, denser and more contaminated crude feeds can greatly increase refinery energy intensity, air emissions, toxic pollutant releases, flaring, and catastrophic incident risk. The DEIR does not disclose or describe these impacts.

24. Changes in the fuel burned to heat, pressurize, and power refinery process equipment that would result from the project are not described adequately in the DEIR. It acknowledges a substantial shift in fuels to be burned but does not report the chemical composition of the current mixture of gasses burned or the changed mixture to be

[39] See: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx.
[40] Thomson Reuters DECEMBER 13, 2012 / 01:30PM GMT, PSX – Phillips 66 First Annual Analyst Meeting. (www.streetevents.com).

burned. Some of this fuel gas composition data is available,[41] but it is not included in, or analyzed by, the DEIR. The mixture of chemicals burned must be identified and analyzed to support complete and reliable estimates of project air emissions.

25. Similarly, as the project causes the refinery to burn more fuel for energy it lowers the fuel's heat content, changing combustion conditions when it is burned. The DEIR provides no information about changes in the equipment that would burn this changed fuel refinery wide. For example, it is troubling that the company first asserted the lower heat content of refinery fuel gas "will require alterations to the burners of 19 heaters to operate efficiently," but now asserts that "no changes to any burners are required at this time," without providing design capacity data for its burners requested by air officials.[42] The DEIR does not mention this issue or correspondence, but this type of data on combustion equipment that could be affected by project fuel changes must be reported and analyzed to support a complete and reliable analysis of project impacts on flaring.

26. The DEIR does not disclose a part of the project that would enable emission increases that could cancel out its claimed SO_2 emissions reduction. Phillips 66 seeks "emission reduction credits" that could be banked and then used later, allowing the refinery to increase emissions by the credited amounts. In its application for air permits submitted for this project eight months ago, the company references the SO_2 emission reduction associated with the project that also is asserted in the DEIR, and then states:

> "Phillips 66 requests 174.7 tons per year of SO_2 emission reduction credits (ERCs) for this reduction. Of this amount, 7.61 tpy will be used to offset project SO_2 increases so that there will be no net increase in SO_2 emissions from the project (see Table 3-1). The remaining 167.1 tpy of SO_2 (174 tpy minus 7.61 tpy) will be banked as ERCs."[43]

This part of the project, to increase emissions later, and this "no net increase" claim, contradict the DEIR's unqualified assertion that the project will result in reducing refinery wide SO_2 emissions "by at least 50%."[44] The DEIR does not propose any condition of approval requiring that the promised refinery wide emission reduction be

[41] See project Air Permit Application attachments A-4 and A-7 (Air Permit App Atts A 4 & 7).
[42] See Phillips' letters of 30 April 2013 (page 1) and 28 June 2013 (page 14) responding to BAAQMD letters of 1 March and 21 May, 2013 advising that its air permit application for the project is incomplete, and presenting numerous data requests (Air Permit Correspondence).
[43] Air Permit Application at 17, Section 3.4 (Air Permit App Sections 1–3).
[44] DEIR at ES-2, 3-5, and 4.3-19.

permanent. It does not identify the now-apparent link, between undisclosed future activities, and this project that could allow those future activities to pollute. It does not evaluate what those activities entail, whether they are part of the project or related to it in other ways as well, why the future rebound in emissions seems necessary, how soon it might occur, or how long it might last. Omitting plans to enable emissions that the DEIR is at the same time asserting will be cut appears misleading. In any case, this part of the project conflicts with the project objective to reduce emissions that is stated in the DEIR.

27. Waste heat from burning fuel to operate the project would be transferred to San Francisco Bay by expanding "once-through cooling" (OTC) that sucks Bay water into the refinery and discharges it back to the Bay as thermal waste. The DEIR does not report how much more heat the project would dump into the Bay. Moreover, its analysis of Bay water use, which *should* indicate the extent of thermal and other impacts of the OTC expansion, underestimates the potential increase in OTC water and heat flows.

28. According to the DEIR, the OTC expansion to 57.6 million gallons/day (MGD) represents an increase of 12.2 MGD from a project baseline OTC flow of 45.4 MGD.[45] The DEIR asserts this 45.4 MGD baseline without any supporting documentation, but NPDES findings omitted from it show that average OTC flow never approached 45.4 MGD since at least 1985. See Chart 3. Further, the refinery was required to estimate impacts of related prior modifications on its OTC flow and estimated they would increase it to only ≈35.4 MGD.[46] Permit review analysis of post-modification continuous monitoring data to check on that estimate found OTC flow of ≈35.5 MGD in 2010, and by mid-2011 this monitoring showed a long-term average OTC flow of ≈38.3 MGD.[46] This evidence shows that the 45.4 MGD DEIR estimate inflates the project's OTC baseline. Based on the proposed OTC expansion to 40,000 gpm (57.6 MGD) and the most recent NPDES long-term average OTC flow (38.3 MGD), the project could use ≈19.3 MGD of Bay water. This more accurate OTC flow increment (19.3 MGD) exceeds the increment the DEIR calculated from its inflated baseline (12.2 MGD) substantially.

[45] DEIR at 3-27; see also Phillips, 2012b at 23–24: The same 40,000 gpm post-project total and 8,500 gpm increase on a purported 31,500 gpm baseline is asserted without documentary support in both, but 40,000 gpm is the proposed OTC rate that would be implied by project approval.
[46] NPDES Permit R2-2011-0027 at F-53 and Finding II. B. 3; see also Table E-5.

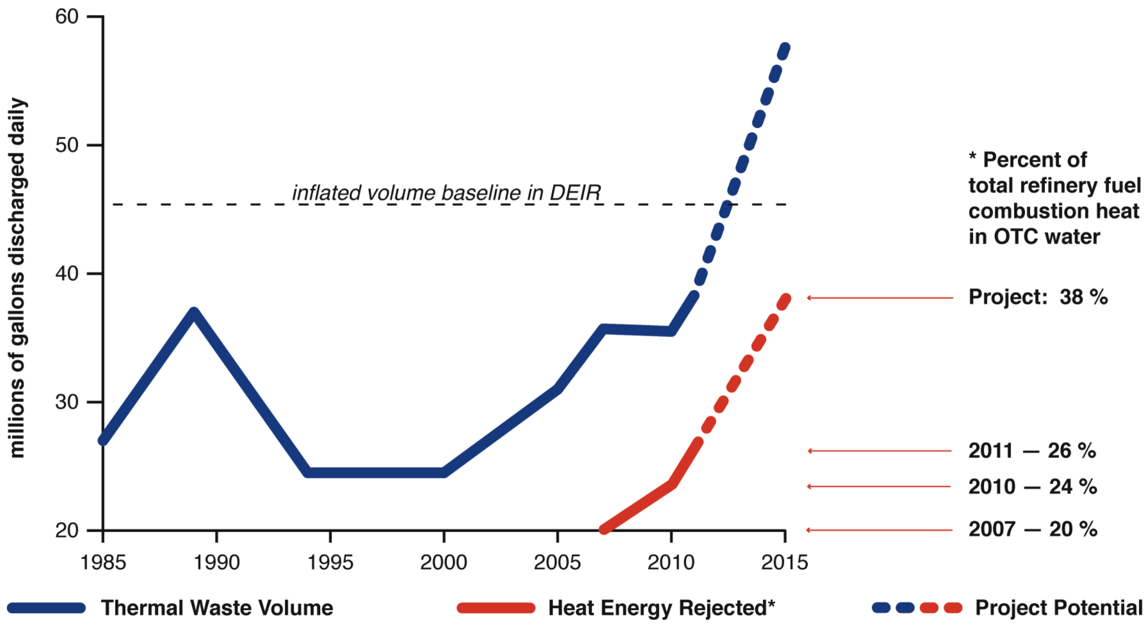

Chart 3. Rodeo facility combustion heat transfer to S.F. Bay. Thermal waste 1985–2011 volume data from NPDES orders R2-1985-029, 1989-002, 1994-129, 2000-015, 2005-0030 and R2-2011-0027; project potential volume from DEIR. Heat energy rejected is shown as a percentage of total refinery fuel energy (DEIR tables 4.6–1, 4.6–2) and is estimated based on volume entering OTC at 55 °F (Reg. Monitoring Program, Davis Pt. Oct–June avg.) and exiting processing at 110 °F before heat loss to the atmosphere and mixing in the retention system upstream of the outfall, and the specific heat of water (4.1868 J). Project potential heat percentage based on 2011 fuel use plus 140 MMBtu/hr for project steam.

29. Total heat rejected by OTC would grow, from ≈6.3–6.8 million gigajoules/year during 2007–2011 to ≈10.2 MM GJ/yr as a result of the project.[47] Waste heat rejected by the project flow increment (≈3.4–3.9 MM GJ/yr) would greatly exceed the total energy of additional fuel the DEIR states the refinery could burn for the project (1.23 MM GJ/yr).[48] Consequently, refinery wide reliance on OTC to reject waste heat would grow, from ≈20–26% of all fuel energy burned in the facility during 2007–2011, to ≈38% of post-project refinery energy use.[49] See Chart 3. The DEIR does not identify or explain the discrepancy between the fuel it says the project would burn and the heat its expanded OTC could carry, and it does not disclose this increased refinery wide reliance on OTC.

[47] 1 gigajoule (GJ): 1 billion joules; 0.994 MMBtu. Waste heat rejected estimated as summarized in the caption of Chart 3. Note that the DEIR does not report the temperature of water exiting processing before entering the retention basin and mixing with other flows around the splitter; it states only that heat loss in those upstream steps will keep the OTC discharge at E-002 ≤ 110 °F.
[48] Based on 140 MMBtu/hr expanded steam boiler capacity (see DEIR at 3-20; 3-21) at 100% utilization. Note that even the DEIR's underestimated OTC flow (≈2.16 MM GJ/yr) would reject more heat than this expanded boiler firing would add: the DEIR does not identify the discrepancy.
[49] Based on annual fuel use in DEIR at 4.6-2, and project adding 140 MMBtu/hr to 2011 fuel use.

30. This increased reliance on OTC to carry heat from as-yet unidentified sources is consistent with an undisclosed increase in firing rates to process denser, higher sulfur crude feeds—which are known to increase refinery energy intensity.[50] It is consistent, also, with a shift from existing cooling towers to OTC—which might yield savings on cooling tower makeup water and chemicals.[51] Confirming or quantifying either or both possibilities may require cooling system design information that the DEIR does not provide. Regardless of its specific uses in cooling the refinery, however, the project's expansion of OTC would conflict with ongoing efforts to phase out and replace OTC.

31. In 2010 California adopted the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.[52] Among other things, this policy required power plant cooling systems to reflect the best technology available, encouraged them to use recycled water instead of estuarine water, and required most plants to cease OTC for units "not directly engaged in power-generating activities or critical system maintenance" by October 2011.[52] Importantly, oil refining is not addressed specifically by this policy at least in part because most California refineries replaced OTC with "closed loop" cooling towers long ago. In fact, the Rodeo facility is the only one of the five refineries lining the Bay that still uses this antiquated cooling technology[53]—and it has been since the Richmond refinery phased out and replaced OTC in the 1980s. The DEIR does not discuss this crucial context.

32. Work that could lead to phasing out and replacing OTC at the refinery has been ordered by the California Regional Water Quality Control Board. The Board ordered the refinery to prepare an engineering evaluation of replacing OTC, including a "conceptual design for a closed loop cooling tower system, including estimated costs (capital and operation) and construction timetable."[54] Phillips' 2012 response reported locations where two cooling towers could be built to replace OTC, conceptual designs for them, and estimated capital ($50 MM) and operating ($5.5 MM/yr) costs.[51] For context, this estimate suggests that the annualized cost over ten years represents only 0.2–0.3 % of the refinery's annual cost for $75/b–$115/b crude. The DEIR does not include or discuss this state order to evaluate replacing OTC or this refinery report indicating it can be done.

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[50] See Karras, 2010; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson, 2012.
[51] See *Cooling Tower Replacement Feasibility Evaluation* (Phillips Cooling Tower).
[52] As adopted by the State Water Resources Control Board on 1 October 2010 (SWRCB, 2010).
[53] Chevron R2-2011-0049; Shell R2-2012-0052; Tesoro R2-2010-0084; Valero R2-2009-0079.
[54] NPDES Permit R2-2011-0027 at Provision VI.C.2.f.

33. Evidence discussed in paragraphs 27–32 indicates that, by building onto and expanding the existing OTC system at the refinery, the project would foreclose an opportunity to replace OTC in the near term, and would instead continue and expand the use of this antiquated cooling technology. It would thereby result in the continuation of adverse impacts on aquatic life in San Francisco Bay that could otherwise be eliminated, in addition to the impacts from project increases in OTC flows. However, the DEIR seeks to evaluate only impacts from its (under)estimate of the increased OTC flow rate, further underestimating the project's potential impacts on the Bay.

34. Once-through cooling harms aquatic ecosystems by injuring or killing biota and degrading their habitats via entrainment,[55] impingement,[56] and thermal pollution.[57] In operation at design temperature, the severity of system- and site-specific impacts is generally proportional to OTC flow. Clearly adverse impacts have been documented from entrainment and at shoreline thermal discharge sites in San Francisco Bay,[58] but monitoring studies have yet to measure the full ecological impact of site-specific OTC applications. This is in part because of practical limitations in scientific tools. For example, reviews of a series of Bay OTC impact studies[59] found:

- Sampling techniques can be too aggressive for some species that become mutilated and unidentifiable or too passive to capture and account accurately for other species.
- Perceptions about the cost of comprehensive sampling lead to excluding many species or life stages—such as phytoplankton, invertebrates, eggs, and species present in very low abundance—and to attempts to measure "surrogate" species instead.
- Similarly, multi-year sampling is seldom done, but interannual variability changes the occurrence and abundance of many species affected by OTC in estuaries like the Bay.
- Sampling and data management designs must anticipate seasonal and spatial variation in the abundance of various species and life stages, but the site-specific timing of such changes is difficult to predict in many cases and may be impossible to predict for some poorly studied species.

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[55] The organism enters into the cooling system with water drawn through the intake screens.
[56] The organism is held against the intake screen by the force of the water flowing into the plant.
[57] Habitat is degraded or lost to various species when the ambient water temperature rises locally.
[58] For example, Mirant Corp. expected aquatic plant and invertebrate species to rebound if its Potrero power plant's thermal discharge was removed from a shoreline outfall (*Construction and Thermal Impacts First Quarter Larval Fish Assessment, 2001-2002*), and entrainment in the 226 MGD Potrero OTC flow was shown to kill an estimated 241–321 million larval fish annually (CBE, 2006). Impacts from the project's 57.6 MGD flow may be different from those of that different OTC system in another part of the Bay, and lesser or greater proportionate to its flow.
[59] See CBE, 2006.

- Taxonomic identification, especially in samples with small numbers of nonabundant or mutilated organisms among large numbers of another species, requires judgment.
- Rates of survival to reproductive age for larvae or juveniles affected by entrainment are generally not measured directly, and are instead inferred from generalized life history data that may be inaccurate or incomplete for certain species or populations.
- Indirect impacts, such as those from loss of forage (food supply) for another species, may be significant, but are difficult to measure and generally are not measured.
- Undersampled species may disproportionately affect the ecological system studied.
- Measurement limitations—such as those mentioned here as well as sampling losses and other anomalies—must be tracked and interpreted in analysis of the data.

Thus, OTC impact studies involve many judgments that are ultimately subjective and yet may determine whether impacts are detected. Compounding the problem in another way, these studies are typically sponsored by plant operators who prefer to avoid replacing OTC. For these reasons, the best practice standard for environmental review of OTC impact monitoring studies includes some form of independent peer review during study design, study implementation, and interpretation of study results. The DEIR does not identify any of these limitations in biological monitoring studies of OTC.

35. No description of the biological effects of OTC *expansion* is provided in the DEIR. Its full discussion of biological effects from the OTC system itself—except for admitting that endangered species are at increased risk of adverse impact—is one long sentence about an old study of intake impacts:

> "The Refinery documented the effectiveness of the wedgewire screens in 2006, estimating that their configuration virtually eliminated impingement of adult and juvenile fishes and significantly reduced entrainment of larval fishes; the location of the intake structure provides effective sweeping flow velocities that, combined with low through-screen velocities at maximum pumping rates, minimize the entrainment of larval fishes."[60]

The DEIR thus does not discuss the extent to which this study: measured all potentially impacted species; used sampling techniques that were effective for all species targeted; identified all targeted species in each sample accurately; monitored or accounted for the great interannual variability of the estuarine impact zone; captured seasonal and spatial variability in OTC impacts; measured long-term survival of entrained or impinged biota and indirect impacts such as forage reduction on other species; measured effects on non-abundant species present, or made proper judgments about these issues in data analysis.

[60] DEIR at 4.4-27. A thermal impact study is not yet done: see Phillips thermal ext 1, 2.

The DEIR does not actually say whether this study collected *any* biological samples. Moreover, this study of 2006 OTC flow conditions does not represent the project's potential for much greater long-term future OTC flow conditions. See Chart 3. The DEIR obscures this important fact by its false assumption that only its underestimated flow increment (12.2 MGD), rather than the full post-project OTC flow (57.6 MGD), should be assessed for potential impacts. The project would increase OTC flow more than the DEIR's inflated baseline discloses *and* would cause the full expanded OTC flow to continue when it otherwise could be eliminated, as discussed in paragraphs 27–33. Accordingly, this 2006 study, and the DEIR itself, does not describe the biological implications of the expanded OTC flow that would result from the project.

36. Instead of describing these environmental implications of the project, the DEIR asserts that any impacts from the OTC expansion will be less than significant because of NPDES permit limits.[61] This assertion is contradicted by facts that the DEIR does not disclose, but in a vain attempt to support it, the DEIR makes a series of erroneous statements that describe the project and its setting inaccurately. In a paragraph referring to an allowable "maximum discharge temperature of 110 ºF" the DEIR asserts:

> "By using sufficient cooling water to ensure that maximum temperatures remain in compliance with the NPDES permit, no significant impacts on special-status fishes would occur."[62]

This statement is clearly erroneous because a large enough volume of 80–110 ºF thermal waste would injure or kill fish that are adapted to 55 ºF water,[63] but it also is misleading. This statement only makes sense if the heat in the 57.6 MGD discharge diffuses rapidly. The statement thus invites the inference that the Rodeo OTC discharges via a deepwater diffuser—a technology so universally required that a proper environmental review would surely note the anomaly if that was not the case—but that is not the case. The antiquated OTC discharges from a shoreline outfall. See Map 1 discharge point 003. Consequently, the thermal waste receives little or no initial dilution, greatly exacerbating its localized impact, and NPDES permit limits allow that, but the DEIR does not disclose these facts.

[61] DEIR at 4.4-27 and 4.4-28; see also DEIR at 4.10-24. It is acknowledged that deferring to future actions by others to address impacts has serious policy and legal implications that require analysis beyond the scope of this report.
[62] DEIR at 4.4-28.
[63] This water temperature (≈55 ºF) is typical in the ambient water of San Pablo Bay near the OTC outfall. See Regional Monitoring Program, Oct–Jun average for Davis Point (Site BD40).

Map 1. Rodeo facility outline, discharge points, and intake points. Attachment B to NPDES Permit, Order R2-2011-0027. The left-most circle containing a cross denotes discharge point E-003.

37. Compounding its error, the DEIR further explains its reliance on NPDES limits by asserting that "the NPDES permit establishes maximum once-through volumes."[64] This statement is untrue. The permit limits several pollutants in the OTC thermal waste discharge at outfall E-003 but flow volume is *not* limited by this permit.[65] The 56% increase in OTC flow during 2000–2011, a period when two permit orders document concerns over OTC impacts that remain unresolved,[65] demonstrates the fallacy of the DEIR's flow limit assertion poignantly. <u>See</u> Chart 3. The DEIR's misplaced focus on permit limits also obscures the permit's ongoing effort to develop closed loop cooling to replace OTC and eliminate its impacts—a crucial effort that the project would foreclose.

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[64] DEIR at 4.4–23; <u>see</u> also 4.4-27.

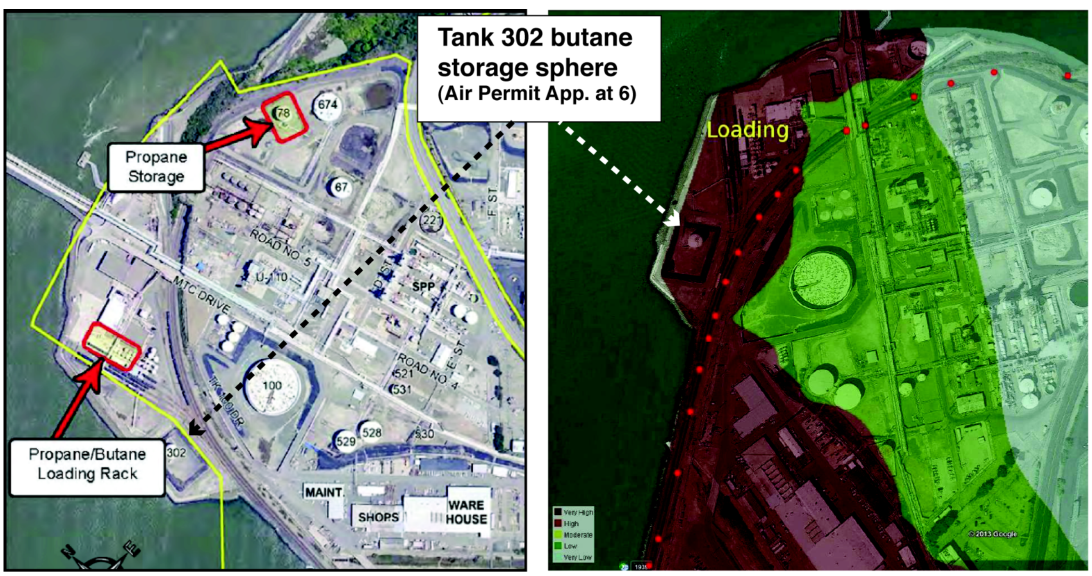
[65] All NPDES permit limits on the OTC (E-003), for ºF, TOC, Cl, Cu, Ni, Zn, and dioxins, are given in tables 8–11 of NPDES Permit Order R2-2011-0027, and flow volume is *<u>not</u>* among them. Provisions VI.C.2 d–f of this Order, and provisions D.9 and D.10 of Order R2-2005-0030 document ongoing, unresolved concerns regarding impacts of the OTC during this period.

38. Remarkably, the DEIR admits that the project's expansion of once-through cooling has the potential to adversely impact threatened or endangered fish species without specifying which ones. It states: "[S]pecial-status fish species identified in Table 4.4-1 that may be present along the Refinery shoreline on a seasonal or year-round basis … are potentially at risk of being entrained in intake pipes, and this risk could increase due to the increased volume of once-through water that would be required under the Project. … . These fishes [also] could be subjected to an increased risk of injury, death, or habitat reduction at effluent discharge locations"[66] The DEIR defines "special-status fish species" to include, among others, the Southern DPS–Green Sturgeon, the Central California Coast and Central Valley DPS–Steelhead, the Central Valley Spring-run Chinook Salmon, and the Winter-run Chinook Salmon—all federally listed threatened or endangered species.[67] The severity or importance of this potential impact may depend in part upon which of the endangered or threatened species face this project risk, but the DEIR does not provide that information, or at least does not do so in an easily understandable form.

39. LPG taken from cracking byproduct gases and treated in the refinery would be stored in new propane and existing butane tanks before loading to railcars via two new rail spurs and a new two-sided loading rack, according to the DEIR project description.[68] The DEIR acknowledges that although this occurs very rarely, the potential exists for a catastrophic failure of an LPG storage vessel such as a "boiling liquid expanding vapor explosion."[69] However, the DEIR describes it as occurring too rarely to warrant analysis of mitigation, and describes cooling the LPG storage tanks instead of pressurizing them (which would eliminate this catastrophic risk) as "infeasible" because of the added costs for electricity and a new flare.[69] Impacts of such an incident could be catastrophic and irreversible. The DEIR does not include or describe the documented Process Hazard Analysis or Inherently Safer Systems Evaluation required by the County Industrial Safety Ordinance (ISO) for the project, and thus does not disclose that those requirements contradict its analysis.

[66] DEIR at 4.4-27. The quote continues, with a qualifier regarding the thermal impact reading *"if those temperatures exceed permitted discharge limits."* However, the DEIR wrongly assumes the increased volume of hot shoreline discharge that receives little or no dilution is controlled by permit volume limits and will not impact the fish, as discussed in paragraphs 36 and 37.
[67] DEIR at 4.4-9 and 4.4-10 (Table 4.4-1).
[68] DEIR at 3-6, 3-17, 3-21 and 3-25.
[69] DEIR at 49-2, 4.9-18, 4.9-19 through 4.9-22, 6-5.

40. Process hazard analysis (PHA) requires, among other things, rigorous determination of the site-specific likelihood of particular hazardous consequences.[70] "Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process."[70] For example, a comprehensive PHA for the project's new propane and additional butane storage would identify and analyze the increased probability of catastrophic failure caused by soil liquefaction in an earthquake—a serious site-specific risk in the seismically active East Bay. At least one of the tanks that would store project LPG is sited on a shoreline plot[71] at high risk for soil liquefaction. See Map 2. This would increase the probability of catastrophic failure involving LPG storage over time. The DEIR, however, estimates this probability based on generalized industry-wide estimates of its frequency.[72] Because it does not describe or evaluate the site-specific conditions, the DEIR underestimates the probability of a catastrophic event.



A. Detail from DEIR Figure 3-3. **B. Seismic shaking / liquifaction hazard overlay**

Map 2. Project-related LPG storage near loading, and earthquake liquefaction hazard
Note the two plate's different orientation to North. Plate B from Ed Tannenbaum and Danielle Fugere.
Burgundy shading in the area near the shoreline (Plate B) indicates very high liquefaction hazard.

[70] CSB, 2013 at 40; see also CSB at 32.
[71] Project butane would increase this and other tanks' throughput. DEIR at 3-21/26, 4.5-7, 4.9-1.
[72] DEIR at 4.9-18; see also AICE, 1989 at 205.

41. County Hazardous Materials Program staff have informed Phillips 66 that they expect "revised siting studies with placing new equipment and associated impacts to existing processes including locations that house personnel (e.g., control rooms, admin buildings)" for the project.[73] These studies would detail what comparing maps 1 and 2 shows: Project-related LPG storage is located relatively close to a concentration of other vessels containing flammable hydrocarbons, the administration building, parking lots, and thus numerous plant personnel. However, the DEIR describes only "moderate" consequences of a catastrophic LPG storage incident, and explains that this is "primarily due to the large distances to the *off-site receptors* (730 to 1340 m.)."[74] *(Emphasis added.)* Its incomplete description of the project's setting causes the DEIR to ignore workers and underestimate the magnitude of this catastrophic risk.

42. Cooled instead of pressurized liquefied gas storage could eliminate the risk of catastrophic LPG storage vessel explosion. Because it is practicable and safer than the proposed pressurized storage for this identified catastrophic hazard, cooled storage could be defined as an inherently safer system with respect to this hazard. In contrast to the DEIR's failure to analyze this mitigation, the ISO *requires* documented inherently safer systems analysis for new processes and facilities.[75] The U.S. Chemical Safety Board recommends that inherently safer technology should be implemented to drive risk as low as reasonably practicable (ALARP), and notes that: "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process … rather than after the process is already operating."[75] Furthermore, in contrast to the DEIR's description of cooled storage as "infeasible" due to the costs of additional electric power and a new flare, the ISO seeks to implement inherently safer solutions "to the greatest extent feasible."[75] There is no cost exemption for affordable cooled storage. The DEIR's description of catastrophic hazards is in error, and its failure to describe inherently safer systems requirements for the project obscures this error.

43. CHMP staff also expect documented human factors evaluations of processes and procedures for the project.[73] These could include, among other things, evaluation of "safety culture" problems that may incent company management to defer safety measures

[73] 11 July 2013 letter from Michael Dossey to Jim Ferris, Phillips 66 (CCHMP–Phillips). The DEIR does not include these process-specific studies or evaluations or discuss their results.
[74] DEIR at 4.9-21.
[75] ISO § 450–8.016(d)(3); <u>see</u> also CSB, 2013 at 40, 45–47, and 55. The DEIR does not include or discuss the Chemical Safety Board's findings, or even its recommendations to the County.

as a shortsighted way to cut costs.[76] But the DEIR does not include or report on this human factors evaluation, and although it is relevant, the DEIR does not discuss this safety culture issue. Chevron management deferred at least six worker requests to inspect or replace a piping circuit over ten years, before that severely corroded pipe ruptured catastrophically in the 6 August 2012 Richmond refinery fire.[77] In another example of poor safety culture, the BP Texas City refinery explosion in March 2005 killed 15 people and injured 180 after BP management—in part to boost profits by avoiding short term costs—deferred replacement of a blowdown stack with a flare.[78] Similarly, the DEIR assumes a bias in favor of avoiding the cost of a flare in its inappropriate failure to analyze identified mitigation for a catastrophic hazard presented by the project.

44. Chemical spills, fires, and explosions at U.S. oil refineries killed at least 30 and injured at least 15,211 workers and nearby residents since 1999.[79] At least 49 upset "emergency" incidents occurred at Bay Area refineries since March 2010.[80] At least 30 such incidents occurred at California refineries in a recent five-month span.[81] The DEIR does not describe or discuss this important context for review of project hazards.

45. Exporting 8,000 b/d of additional LPG from the refinery for sale instead of burning that propane and butane in its fuel gas would change the location of emissions from LPG created by refinery processes. Although selling this LPG for purposes that obviously include burning it is the primary objective the DEIR states for the project, the DEIR does not identify or describe the resultant off-site impacts or provide information about specific end uses of this LPG.[82] Those potential emissions are substantial: the

[76] Chevron Safety Audit Oversight Committee, 2013. Audit Scope of Work.
[77] CSB, 2013: see esp. 36–42.
[78] Chemical Safety Board incident investigation (CSB, 2005). See esp. page 253: In one instance BP managers decided on in-kind replacement of the hazardous design in part to "maintain profits" by avoiding new source standards that likely would have required connecting to a flare.
[79] U.S. Chemical Safety Board incident investigation reports (www.csb.gov). Injuries include hospital visits associated with the 2012 Chevron Richmond refinery fire.
[80] Flare causal analyses submitted to Bay Area AQMD pursuant to Rule 12-12, §406.
[81] Labor Occupational Health Program, U.C. Berkeley, 2013 (LOHP).
[82] BAAQMD asked for the end uses of this LPG but like the DEIR, the company did not report them (see Air permit correspondence). Because of this nonreporting only a "potential to pollute" estimate is possible, but it is reasonably foreseeable that virtually all project LPG exports could be burned. Combustion activities (residential, C4 gasoline addition, industrial and recreational) are the primary end use of LPG sold nationally, and markets are highly regional; LPG use for petrochemical feedstock is highly concentrated in the Gulf Coast. Shipping costs to sell Rodeo LPG in the Gulf Coast would make it less competitive than Gulf Coast LPG supplies.

DEIR estimates that the LPG the project would remove from refinery fuel gas would emit greenhouse gases (GHG) at a rate of 759,244 tonnes/yr.[83] But instead of identifying, describing, or accounting for the resultant off-site impacts, the DEIR subtracts this amount from its project GHG emission estimate. The DEIR thereby assigns offsite LPG emissions a value of zero—even though it accounts for project emissions from outside the refinery gate for transport, and electricity generation—erroneously calculating a net decrease in GHG emissions (–325,978 tonnes/yr) when the correct net emissions, by its own estimate, total 433,266 tonnes/yr (–325,978 + 759,244).[83] Thus, project emissions could exceed the 10,000 tonnes/yr threshold of significance for GHG emissions used by the DEIR substantially. The DEIR does not identify a potential impact that would be significant, in part because it does not describe LPG environmental implications of achieving the project's main stated goal outside the refinery gate.

46. Byproduct coke production would increase along with cracked LPG gases for the project, but the DEIR does not say how much, or whether this additional petroleum coke will be exported, burned in the refinery, or both. Increased coking of denser feeds might increase coke production by thousands of barrels/day, and coke burns much dirtier than the gases the DEIR assumes the refinery will burn.[84] Burning the extra coke created by the project in place of other refinery fuel could increase refinery emissions substantially.

47. The DEIR does not explain that the company's Rodeo Facility (RF) and Santa Maria Facility (SMF) are two parts of one integrated refinery. The SMF and RF are linked by a pipeline sending crude and intermediate oils between them,[85] their processes are integrated to a capacity that neither can achieve alone,[86] and Phillips 66 reports them as a single processing entity to industry and government monitors[86] that is called the "San Francisco Refinery."[85] Omitting all of this, the DEIR also fails to explain the extent to which this project, and the concurrent SMF expansion to increase production and pipeline shipments to Rodeo,[85] are two parts of a single, larger, project that remains undisclosed.

[83] See DEIR at 4.8-18, Table 4.8-3
[84] Denser feeds might increase coke yield on coker feed volume by ≈10% (see tables 7.1-2, 7.1-6 in Meyers, 1986), not counting the effect of increasing coker feed volume. As compared with CO_2 emissions of ≈67.7 kg/GJ fuel gas and ≈56.0 kg/GJ natural gas, burning petroleum coke emits CO_2 at a rate of ≈108 kg/GJ. See Karras, 2010 at Table S1.
[85] SMF EIR 2012 Excerpts (attached). See esp. pages 2-1 (describing SMF–Rodeo integration), 2-11 (processes, and intermediates sent to Rodeo), 2-25 (project would increase deliveries of oils to Rodeo via pipeline), and 2-26 (project potential for 408,255 tons/yr increase in coke produced).
[86] See *Oil & Gas Journal*, 2012; and EIA Ref. Cap. 2013. See also orders R2-2011-0027 and R3-2007-0002. Comparing the references shows "Rodeo" capacities reported to EIA include SMF.

Project Impacts on the Environment

48. Project emissions would exceed a climate significance threshold, as the DEIR's emission estimates show, when its failure to account for emissions from burning project LPG is corrected. See paragraph 45. A check on its estimates, accounting for the 8,000 b/d of LPG (464,243 m^3/yr) sold and replaced by natural gas for refinery fuel, confirms that project GHG emissions would exceed the significance threshold established in the DEIR by more than 40 times. See Table 5. These observations make sense because oil refining emits more GHG than any other industry in California,[87] and the project would increase fossil fuel combustion associated with the refinery's activities substantially.[88] Among other potential measures to lessen or avoid this impact, the County could consider requiring that refinery use of electricity from the grid be purchased from renewable, rather than fossil-fueled, generation sources.

Table 5. GHG emissions from project LPG and natural gas to replace it in fuel gas

	DEIR estimate (CO_2e)[a]		CBE estimate (CO_2)[b]	
	LPG	natural gas	LPG	natural gas
volume (m^3/yr)	464,243	310,000,000	464,243	313,000,000
energy (GJ/yr)	11,230,541	11,230,541	11,900,000	11,900,000
emissions (tonnes/yr)	759,244	592,761	782,000	666,000
change in off-site LPG emissions		759,244		782,000
change from replacing LPG in fuel gas		-166,483		-116,000
net of other project emissions identified[a]		-159,495		-159,495
Total project emissions identified in DEIR		**433,266**		**506,505**
Threshold of significance from DEIR		10,000		10,000

LPG volume shown as liquid, from DEIR Table 3-2. (a) DEIR data from Table 4.8-3, except energy estimate from page 4.8-16 and natural gas volume estimate from Table 3-2. Other project emissions: boiler, mobile source and indirect emissions minus shutdown credit. (b) Based on natural gas energy equivalent to project LPG volume and heat contents (25.62, 0.038 GJ/m^3) and CO_2 emission factors (65.76, 55.98 kg/GJ) for LPG and natural gas, respectively, from Table S1 in Karras, 2010.

49. Stored under pressure, project gases could explode. Because predicting when this catastrophic and irreversible consequence might occur is ultimately speculative, and a safer design that might eliminate this hazard could be precluded after the project is built, the project as proposed would create an *inherent hazard.*[89] The project's failure to

[87] See CARB, 2013.
[88] Project LPG sales burned elsewhere and replaced with natural gas onsite would represent ≈44% of all fuel energy burned in the refinery in 2011, based on DEIR data (see pages 4.6-2, 4.8-16).
[89] See: CSB, 2013 at 40–48, 55.

demonstrate the use of inherently safer systems (ISS)—including cooled instead of pressurized storage, which would eliminate this catastrophic explosion hazard—through a process hazard analysis (PHA)[90] would conflict with the Industrial Safety Ordinance. Therefore, project gas storage under pressure would result in a hazard impact. The DEIR failed to identify the significance of this impact because its analysis ignored hazardous siting conditions and PHA and ISS requirements, and rejected analysis of an inherently safer measure that could avoid a catastrophic hazard based on cost, contrary to safety best practice and the Industrial Safety Ordinance. See paragraphs 39–44.

50. Pressurized gas storage explosion hazard resulting from the project can be mitigated but the DEIR did not complete its analysis of this mitigation opportunity. The County could consider developing an appropriate permit condition requiring cooled storage of propane and butane stored as a result of the project. Developing an appropriate permit condition would require reporting and evaluation of the PHA and documented ISS analyses that were not reported or addressed in the DEIR.

51. Expansion of the existing once-through cooling system would conflict with state plans and policies to phase out and replace this antiquated technology and foreclose an opportunity to replace the system in the near term via ongoing work to implement those plans and policies. Increased impingement, entrainment and thermal waste impacts that would result from the project would adversely impact aquatic biota and have the potential to injure or kill members of the remaining populations of threatened or endangered fish species that depend upon aquatic habitats in the vicinity of the refinery. Therefore, the project would adversely impact the biological resources of the San Francisco Bay-Delta ecosystem in conflict with state plans and policies.

52. The DEIR failed to identify the state plans, policies, and ongoing work the project would conflict with and foreclose by expanding the once-through cooling system. Due to these errors and its assumption of an erroneous project baseline it targeted only a fraction of the intake and discharge flow that would result from the project for its impact analysis. The DEIR reported no biological analysis of actual system effects that includes data representative of the expanded system. Its conclusions ultimately relied on a description of flow, heat, and discharge limitations that is demonstrably incorrect. As a result, it did

[90] No documented PHA or ISS is included in the DEIR, and County safety staff still sought these analyses, *including for cooled storage,* as of 11 July 2013. CHMP-Phillips071113; DEIR at 6-5.

not identify the significance of this impact. See paragraphs 27–38. The County could consider, among other measures to lessen or avoid this impact, requiring replacement of the antiquated once-through cooling system with closed loop cooling towers.

53. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, and this impact could be significant, but the DEIR did not analyze, or include information needed to analyze, this potential impact. The project outlined *in concept* might cut emissions substantially, but the DEIR's claim that refinery wide SO_2 emissions will be cut by 50% is wrong for several reasons. The project application for "emission reduction credits" to *increase* SO_2 emissions by 174.7 tons/yr that Phillips asserts will be used to achieve "no net increase" in project emissions would foreclose an emissions cut. See paragraph 26. Further, if the actual emissions cut from treating and replacing fuel gas is less than 174.7 tons/yr, emissions could increase. The extent of this potential increase cannot be quantified because data to support the emission credits—such as fuel gas hydrotreating specifications, and pre- and post-project fuel gas balances showing the composition and flows of gases among process units—is not included in the DEIR.

54. Importantly, this undisclosed change in the project that would foreclose the promised SO_2 emissions reduction conflicts with the DEIR's stated project objective to reduce emissions. The County could consider developing a land use permit condition that ensures the 50% reduction in refinery wide SO_2 emissions identified in the DEIR will be real, measurable and permanent. Developing an effective condition could be expected to require, among other things, analysis of the fuel gas composition and petroleum coke disposition data that is not disclosed in the DEIR (see paragraphs 24 and 46).

55. Flaring could be caused by fuel gas quality upsets resulting from the project because it lowers the heat content of gases burned throughout the refinery without upgrading equipment designed to burn gases with higher heat content. Fuel gas quality upsets, including those involving low heat-content gases, have caused significant flare episodes at the refinery repeatedly.[91] The company's shifting statements about whether existing burners should be or will be upgraded underscore the potential for increased frequency and magnitude of this type of flaring.[92] Flaring from fuel gas *quality* upsets can occur independently from that caused by fuel gas *quantity* upsets, and the DEIR did

[91] Flare Causal Analysis excerpts; see also CBE, 2007. *Flaring Prevention Measures.*
[92] See paragraph 25; Air Permit Correspondence; see also paragraph 14.

not analyze or mitigate this fuel gas quality issue. Moreover, flaring episodes impact air quality and health via acute exposures around each episode,[93] so that fuel gas quality flaring from the project could cause significant impacts even if the project reduces flaring from fuel gas quantity problems. To support a complete and reliable analysis of impacts on flaring, specifications for the changed fuel gas quality and for all of the combustion equipment that could be affected by this change must be reported and analyzed.

56. Flaring likely would be caused by the crude switch resulting from the project. Three independent reviews following the refining of higher sulfur crude at Gulf Coast and Bay Area refineries found evidence for increased flaring and flare emission intensity from hydrocracker and hydrotreater upsets.[94] This potential impact would not be mitigated by project treatment of fuel gas because the emergency shutdowns of these high-pressure processes that initiate the flaring typically requires dumping their contents to flares, bypassing fuel gas treatment. Indeed, flaring is allowed in emergencies, despite known local air impacts,[95] as a last-resort emergency response safeguard *after* potentially catastrophic conditions begin to manifest. This flaring indicates a process hazard.

57. The DEIR did not describe or evaluate upset flaring or any other impact of the denser, more contaminated crude slate that likely would result from the project. The denser hydrocarbons disproportionately present in denser crude oils have many more carbon atoms, and much lower hydrogen : carbon ratios, than the gasoline, diesel, or jet fuel made from these oils. These dense hydrocarbons also have greater concentrations of contaminants—such as sulfur, nitrogen, nickel, vanadium, selenium, and naphthenic acids, among others—that are toxic, corrosive, poison process catalysts, or decompose in refining processes to form toxic and corrosive compounds such as hydrogen sulfide (H_2S). Density and contaminant content broadly correlate among well mixed blends of whole crude oils from many different locations and geologies.[96] But complicating assessment and further increasing the hazard, this correlation breaks down in the case of

[93] See CBE, 2005. *Flaring Hot Spots;* BAAQMD, 2006 at 6–8.
[94] Subra, 2008; Karras, 2008; Dolbear, 2008 (Dolbear AG Summary). The concise notes from Dolbear's review inform the need to check for unanticipated hazards from crude switching: "This work forced me to think through this system again, and I conclude that, at least in the refineries in question, increasing contaminant levels do result in stressing the system to lead to upsets".
[95] Compare BAAQMD, 2006 at 6–8 (documenting flaring impact on nearby community) with BAAQMD Flare Control Rule 12-12 §101 (nothing in rule should be construed to compromise safety) and §301 (standard allows flaring in emergency to avoid potentially worse consequences).
[96] See Speight, 1991; Karras, 2010.

some individual crude oils that the project could lock the refinery into processing. In particular, partially pre-processed oils[97] and bitumen[98] derived from tar sands can be highly contaminated relative to their density.

58. Lower quality crude is an inherently more hazardous feedstock. Making engine fuels from its denser, hydrogen-poor hydrocarbons requires processing proportionately more of each barrel using severe carbon rejection (e.g., coking) and hydrogen addition (e.g., hydrocracking) and making that hydrogen, increasing refinery energy use and fuel burning for that energy.[99] Its greater contaminant content results in greater amounts of various toxic chemicals passing through the refinery into the environment, potentially increasing fugitive emissions of benzene and other toxics,[98] and in some cases boosting per-barrel releases of toxic trace elements by up to an order of magnitude.[100] The larger volume of toxic, flammable, and corrosive materials undergoing severe processing at high temperature and pressure further increases the frequency of process malfunctions and upsets over time, and the magnitude of these incidents when they occur.

59. Switching to higher sulfur crude was a causal factor in the disastrous Richmond refinery fire on 6 August 2012. See Chart 4. Sulfur corrosion of the pipe section that ruptured catastrophically in the incident (gray shading), sulfur in the gas oil running through this pipe (black line), and sulfur in the refinery crude feed supplying that gas oil (red line) are shown in this chart. The percent change from baselines is shown.[101] As sulfur increased in the crude, it increased in the gas oil distilled from that crude and running through the pipe, and sulfidic corrosion began to thin the wall of this pipe more than four times faster than before that dramatic sulfur increase. See Chart 4. This example of an ultimately disastrous feedstock substitution hazard applies to the SFR and the even more inherently hazardous crude feed that likely would result from the project.

60. Sulfur attacks metal equipment in contact with oil streams at temperatures above ≈230 ºC, causing thinning that leads to catastrophic ruptures, so that "sulfidic" corrosion "continues to be a significant cause of … incidents associated with large property losses

[97] See Karras, 2010.
[98] See Fox, 2013.
[99] See Karras, 2010; UCS, 2011; Bredeson et al., 2010; Brandt, 2012; Abella and Bergerson 2012.
[100] See CBE, 1994; and Wilhelm et al., 2007.
[101] For example, sulfur increased by more than 50% in crude based on crude sulfur content > 1.5 wt. % (Aug 2011–Jul 2012 avg.) versus a baseline < 1 wt. % (1996 avg.). See Karras, 2013.

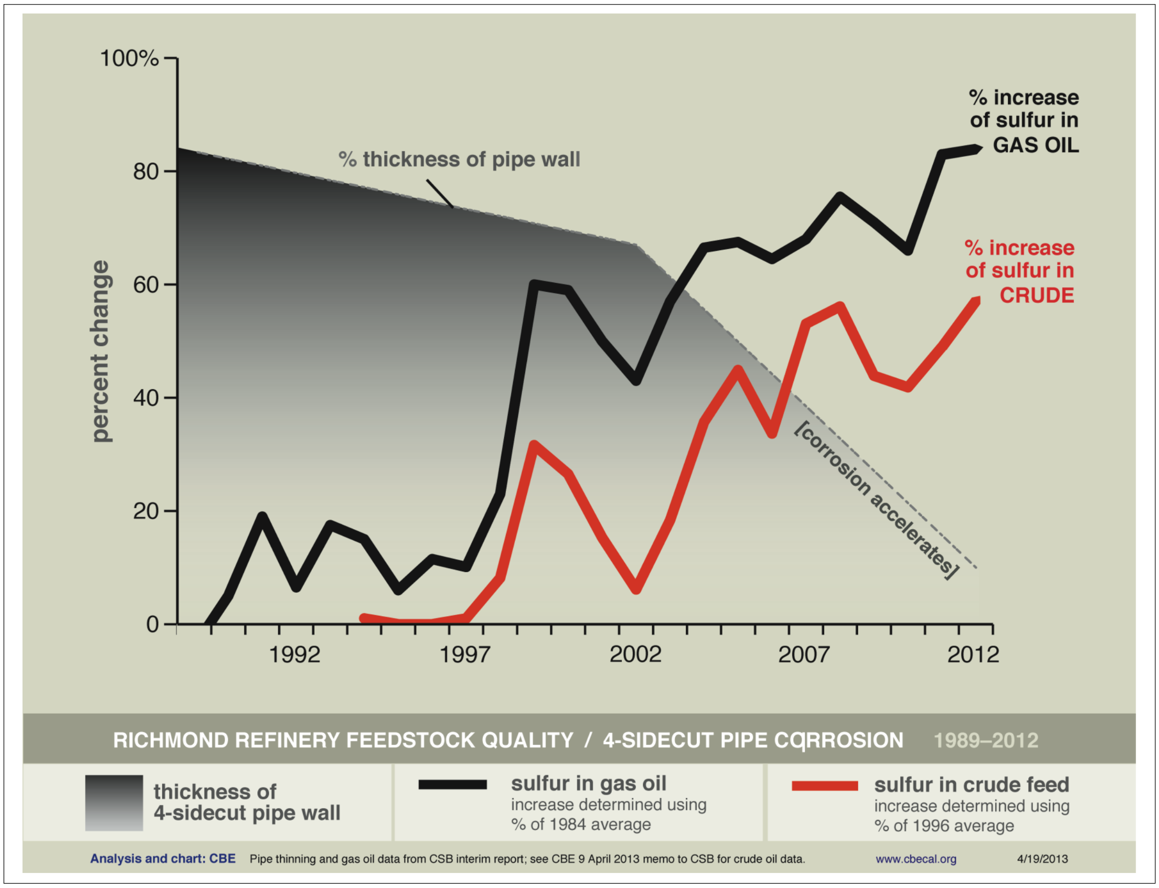


Chart 5. Richmond refinery feedstock quality / 4-Sidecut pipe corrosion, 1989–2012.
From testimony presented in the 19 April 2-13 U.S. Chemical Safety Board public hearing at Richmond, CA.

and injuries."[102] Sulfidic corrosion can occur anywhere in refineries where sulfur-bearing oils are processed this hot.[102] "Process variables that affect [sulfidic] corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system."[103] Higher sulfur crude feeds can accelerate sulfidic corrosion dramatically.[104] See Chart 4. All steels are attacked, but carbon steel, and carbon steel that has low silicon content, are particularly vulnerable.[104] U.S. refineries built before 1985 are especially vulnerable because they likely include low-silicon carbon steel equipment components.[104] Newer equipment can be similarly vulnerable because, perhaps in the rush to build and restart production, it may be made from inappropriately

[102] API, 2009 at vii. See also pages 3–8, and 16; and CSB, 2013 at 29–30.
[103] CSB, 2013 at 16.
[104] See CSB, 2013 at 16–45; see esp. 33–36. see also API, 2009.

corrosion-vulnerable alloys mistakenly installed, and then operated because of this error.[105] Sulfidic corrosion is difficult to monitor: it may accelerate in a few small, vulnerable, yet critical components of refinery piping systems many miles long, requiring monitoring of 100% of the components, but that is costly and may not be performed.[106] Actions taken to cut energy costs have in some cases inadvertently exacerbated sulfidic corrosion.[107] Further, in addition to introducing another hazard, corrosion resulting from naphthenic acids (TAN) in the crude can exacerbate sulfidic corrosion.[108] Ignoring or failing to recognize the nature of this hazard is part of the problem—impacts of a new and different feedstock are at best difficult to predict, and past operating history is *not* a guide to the future hazard when a refinery switches to a new and high-sulfur crude.[109] The proposed project at SFR presents these aspects of this hazard.

61. Sulfur is likely to reach ≈3–4 wt. % in the new crude slate that would result from the project. <u>See</u> paragraphs 12–22. This could cause more aggressive sulfidic corrosion than the increase to ≈1.55 % sulfur that caused the catastrophic pipe failure in 2012 at Richmond. The new crude slate is also likely to include more high TAN tar sands oils that could further exacerbate sulfidic corrosion and create a new corrosion hazard.[110] The Rodeo facility was built before 1985: carbon steel equipment that is especially vulnerable to sulfidic corrosion is likely present in the plant. The project as proposed documents no positive materials identification program that is addressing this vulnerability. Nor does it document any management of change, process hazard, or inherently safer systems analysis of this hazard, in conflict with the ISO and industry standards.[111] The project, as proposed, would create a catastrophic hazard resulting from switching to a new crude and rely, in essence, on past operating history to address this hazard. That is unsafe.

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[105] Incorrect alloys for corrosion resistance may have been installed mistakenly in up to 3% of piping components and 10% of items such as drain plugs at some refineries (API, 2009 at 16).
[106] <u>See</u> CSB, 2013 at 16–45; <u>see</u> esp. 33–36. <u>see</u> also API, 2009.
[107] <u>See</u> API, 2009 at 8; CSB, 2013 at 33.
[108] Total acid number (TAN), measured in mg KOH/g oil, reflects organic acids in crude oils that refiners call “naphthenic” acids. “[I]t is important to note that naphthenic acids can dissolve the iron sulfide scale [that might otherwise slow sulfidic corrosion] or at the very least render it less protective. ... [and it] is often difficult to isolate the individual effects of naphthenic acids and sulfur compounds [but] naphthenic acid never lowers sulfidation corrosion.” API, 2009 at 4.
[109] CSB, 2013 at 35; API, 2009 at 5, 7, 8 and 16.
[110] TAN ranges from ≈0.9– 1.7 mg KOH/g in tar sands oils that are likely to be refined as a result of the project (<u>see</u> Table 3): 0.5 mg KOH/g is considered high for this acid (<u>see</u> Sheridan, 2006).
[111] County safety staff noted these PHA and ISS requirements (CHMP–Phillips071113); failure to analyze corrosion impacts of crude changes also violates industry standards (CSB, 2013 at 36).

62. Chart 5 shows data describing the scale of emissions from burning more fuel for the extra energy to refine denser, more contaminated crude slates. GHG emissions are plotted against crude slate density. Each white circle represents an annual average observed in one of the four largest U.S. Petroleum Administration Defense districts (PADDs) from 1999–2008; each orange diamond an observed California-wide annual average from 2004–2009; and the black square represents the Shell Martinez refinery annual average observed in 2008. The diagonal rise among the 47 observations from left to right in the chart indicates denser crude slates increase refinery emissions. Observed average emissions nearly double, from ≈260–500 kg/m^3 crude refined, as crude density increases from 860–932 kg/m^3. The SFR crude slate density increment that could result from the project (+37 kg/m^3; paragraphs 12–22) is shown by the width of the yellow band in the chart; the right-hand edge of this band shows the density of the WCS/ANS blend that the refinery could run as a result of the project (952 kg/m^3; <u>see</u> Table 4). This crude slate approaches the density of "heavy oil" as defined by the USGS (957 kg/m^3),[112] and is considerably denser than the Martinez refinery observation (932 kg/m^3), which appears near the middle of the yellow band shown in the chart.

63. Analysis that separated crude quality effects on emissions from those of other factors demonstrated that crude density (shown in Chart 5) and sulfur content (not shown) can explain 85–96% of observed variability in emissions among refining regions and years, allowing the prediction of average emissions from crude slates.[113] Predictions based on the U.S. observations suggest that an industry-wide switch to refining "heavy oil" (shown) and bitumen (not shown) could double or triple current U.S. refining emissions.[114] More recent work using different methods estimates emission increments that are generally consistent with these predictions.[115] Also, the U.S. data and methods used in these predictions were found to predict the observed emissions from the Martinez refinery within ≈7% and the long-term 2004–2009 average California industry emissions within ≈1%.[116] Based on these same data and methods, the project increase in SFR crude

[112] Heavy oil average density (957 kg/m^3) and sulfur content (2.9 wt. %) from Meyers et al., 2007.
[113] Karras, 2010; UCS, 2011.
[114] Karras, 2010.
[115] <u>See</u> Abella and Bergerson, 2012 (bitumen and dilbit vs. light conventional oils in Figure 1).
[116] UCS, 2011. <u>See</u> pages 9, 12 and 13, and Table 1-1. Four other refinery-specific predictions were tested as well (not shown in chart). When uncertainties caused by the lack of facility products reporting were considered, observed emissions from 4 of the 5 plants were predicted successfully, and emissions were underpredicted in 1 test. These predictions were tested by withholding the California energy and emission observations from the predictive model.

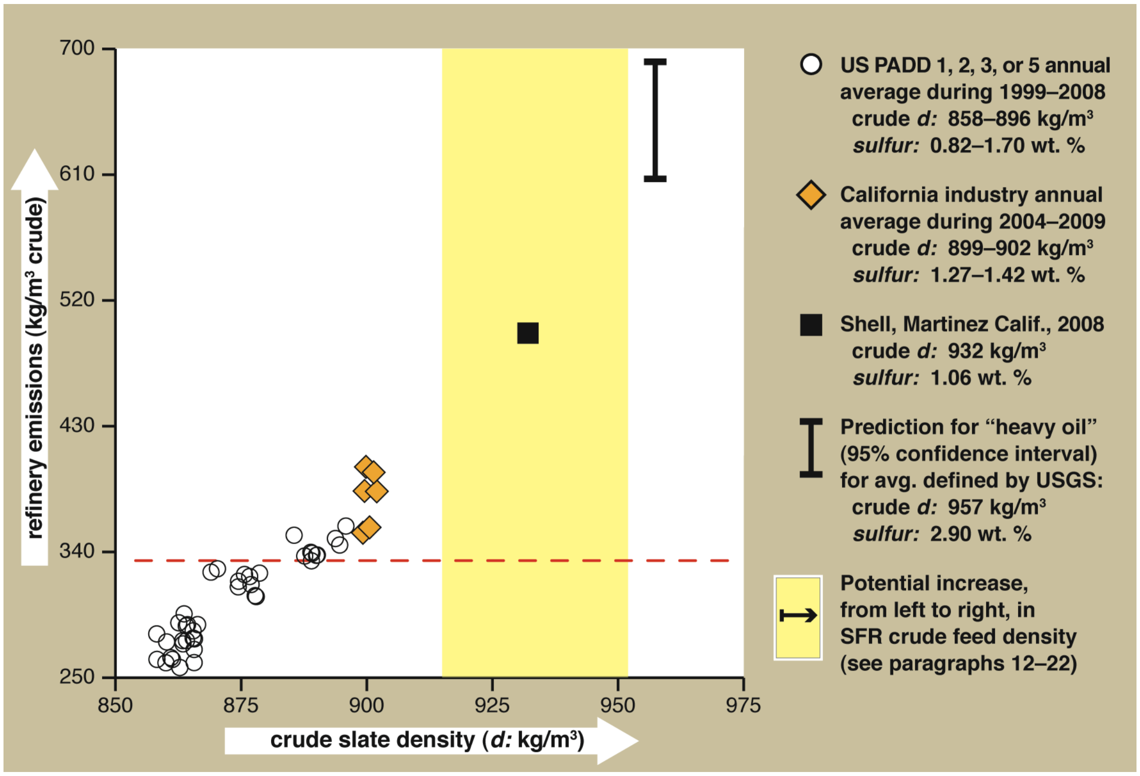

Chart 5. Refinery GHG emission intensity vs. crude feed density. CO_2 emissions increase from ≈260–500 kg per m^3 crude feed as crude density increases from 860–932 kg/m^3. Density (shown) and sulfur (not shown) explain 85–96% of these changes in emissions among refining regions and years. Emissions of ≈610–690 kg/m^3 are predicted from refining the average "heavy oil" (*d,* 957 kg/m^3; *S,* 2.9%). Plant-specific emissions also vary with other properties of oil feeds, products, process configurations and fuels burned, however, the WCS/ANS crude feed shown in Table 4 (*d,* 952 kg/m^3; *S,* 3.4%) is nearly as dense as this heavy oil and denser than a dozen feeds with observed emissions greater than current SFR emissions reported (334 kg/m^3 2009–2011; shown on the vertical scale by the dashed red line). The potential increase in SFR crude feed density (≈915–952 kg/m^3) is shown on the horizontal scale by the width of the yellow band. Each 90 kg/m^3 increment shown on the vertical scale represents emitting 627,000 tonnes/yr at SFR's 120,000 b/d capacity. Data from Karras (2010) and UCS (2011) except SFR emissions (CARB, 2013 for Rodeo and Santa Maria refining and Rodeo Air Liquide H_2 at *Oil & Gas Journal,* 2012 crude capacity).

slate density from 915–952 kg/m^3 and sulfur from 1.5–3.4% could increase the average refinery's energy intensity by ≈2.75 GJ/m^3 crude refined.[117] Assuming the refinery fuels reported in the DEIR,[118] and this average energy increment, SFR emissions of CO_2 would increase by ≈135 kg/m^3, or ≈940,000 tonnes/year. (Each 90 kg/m^3 increment on the vertical scale in Chart 5 represents emission of 627,000 tonnes/yr at SFR's 120,000 b/d capacity.) This ≈940,000 tonnes/yr value indicates the scale of potential impact rather than its precise quantification, as discussed directly below.

[117] Based on baseline and potential central predictions; confidence of increase > 95%.
[118] Based on fuel mix emission intensity ≈64.23 kg/GJ before and ≈59.45 kg/GJ after project fuel switch, from data in DEIR chapters 4.6 and 4.5; emission factors in UCS (2011) Table 2-1.

64. Plant-specific GHG emissions can vary from industry-average increments with differences in fuels burned, product slates, process configuration, and other properties of oils refined.[119] The DEIR's fuel mix assumption is an example of this variability. The relatively less-dirty current refinery fuel mix it reports[120] appears consistent with SFR's current emission estimate that appears somewhat low in Chart 5 (see dashed red line).[121] However, the DEIR's assumption that *only* natural gas will replace the LPG taken from refinery fuel ignores the potential for burning more petroleum coke in the refinery. See paragraph 46. The 940,000 tonnes/yr figure above could underestimate refinery emissions if any of this LPG is replaced by burning the project's extra coke.

65. Anomalous product slates must be considered, in general, because a refinery that makes much less (or much more) of its crude feed into light liquid fuels,[122] requires less (or more) energy for the severe carbon rejection and hydrogen addition processing needed to make these fuels from crude. This refinery, however, reports light liquid fuels production totaling more than 80% of its feedstock volume,[123] and project LPG would boost its light liquids product ratio still higher. The SFR products slate should be quantified and analyzed based on more data than the DEIR reported, but it is unlikely to decrease refinery GHG emissions relative to the industry average products slate.

66. SFR's process configuration could run the denser and more contaminated crude slate that likely would result from the project (see Table 4), but whether it would use more, or less, energy than the average refinery to do so is a more nuanced question. SFR has no catalytic cracker. Although it has very substantial carbon rejection (coking) capacity, this nevertheless makes it more reliant on severe hydrogen addition (hydro-

[119] Karras, 2010; Bredeson et al., 2010; UCS, 2011; Abella and Bergerson, 2012.
[120] See DEIR at 4.6-1, 4.6-2.
[121] This current SFR fuel mix emission estimate (≈64.23 kg/GJ; see note 118) is significantly less than the U.S. industry average (≈73.77 kg/GJ; see Karras, 2010 Table S1), but the SFR emissions reported by the company might be underestimated as well. SFR's emission reports received at least one "adverse" verification finding (CARB, 2013) and its Rodeo facility estimate appears slightly lower than that suggested by DEIR fuels data and UCS (2011) emission factors. These reported emissions (2009–2011 avg. including the Air Liquide Rodeo H_2 plant and Santa Maria facility based on CARB, 2013; kg/m^3 crude based on capacity from *Oil & Gas Journal,* 2012) are shown in Chart 5 because this is the emissions report available. Remarkably, the DEIR did not report *any* GHG emission estimate for the SFR refinery or even the Rodeo facility as a whole—a stark example of its failure to analyze this impact.
[122] Light liquid fuels: gasoline; diesel, jet fuel and similar distillates; LPG.
[123] See Phillips, 2012b at Table 1; EIR SCH #2005092028 at Table 3-4; EIR SCH #2002122017 at Table 4.5-2.

cracking, and associated H_2 production), and less reliant on carbon rejection processing, than a refinery with equivalent coking capacity *and* catalytic cracking. Several studies report that refinery configuration can affect energy intensity, emission intensity, or both—but they do not report specific evidence that substituting hydrocracking for catalytic cracking in a coking-based refinery reduces GHG emissions.[124] Instead, they cite hydrogen addition as a key factor increasing refinery energy intensity.[124] Further, the SFR process intensity exceeds reported averages in major U.S. PADDs by 22–78%.[125] Analysis across the U.S. PADDs did find a shift to a slightly less-dirty refinery fuel mix as refiners shifted from catalytic cracking to hydrocracking,[126] but this effect is accounted for already by plant-specific fuels data (see paragraphs 63–64). More detailed data on the SFR process configuration should be gathered and analyzed to better quantify potential emissions.[127] However, beyond the fuel mix (already addressed), there is little evidence that the SFR configuration will uniquely limit emission impacts from a denser and dirtier crude slate, and no evidence that denser crude can be converted to lighter products without energy—and resultant fuel combustion emission—costs.

67. Other properties of crude oils that affect processing may not be predicted reliably by density and sulfur in a poorly mixed crude slate. Many such properties are analyzed and reported (see Crude Assays). This data could have been included in the DEIR. For example, Abella and Bergerson's public domain estimation method calls for distillation, hydrogen content, and carbon residue data along with crude density and sulfur.[127] The project's coking dependence indirectly provides the key part of this distillation data (see paragraphs 14–20). However, hydrogen is a critical energy and emission driver.[124] Tar sands-derived oils tend to be H_2-poor, and refining them has, in some cases, increased energy use and emissions beyond those predicted by density and sulfur.[128] The project's likely use of these oils may emit more than the industry-average prediction suggests.

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[124] See Bredeson et al., 2010; Abella and Bergerson, 2012; Karras, 2010; UCS, 2011.
[125] Process intensity (*PI*): the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. SFR *PI* (1.60) based on data from *Oil & Gas Journal* (2012); U.S. *PI* (0.9–1.31) for PADDs 1, 2, 3, and 5 in 1999-2008 from Karras, 2010.
[126] Karras, 2010.
[127] The County could quantify potential emissions from the crude switch using non-confidential information and readily available analysis tools. Karras (2010) and Abella and Bergerson (2012) each present methods that are designed to be used with publicly verifiable data. Each method appears to have strengths and weaknesses relative to the other, and ideally, both should be used.
[128] See Abella and Bergerson, 2012; Fox, 2013; Karras, 2010.

68. Evidence discussed in paragraphs 62–67 shows that the crude switch likely to result from the project would increase GHG emissions substantially, and could increase them on the order of ≈1,000,000 tonnes/yr, but the actual increment might be half, or twice, that amount, and the DEIR failed to report data that could narrow this uncertainty. If even half (≈500,000 tonnes/yr) or only one-quarter (≈250,000 tonnes/yr) of this emission potential is realized, the emission increment would exceed the 10,000 tonnes/yr threshold of significance for GHG emissions asserted by the DEIR substantially.

69. Emissions of toxic and smog-forming combustion products could increase along with CO_2 as the project crude switch increases refinery energy intensity, requiring the SFR to burn more fuel per barrel of oil processed.[129] Emission of particulate matter air pollution (PM) is of specific concern. Fine particulate matter ($PM_{2.5}$) is associated with ≈14,000–24,000 premature deaths each year statewide, and $PM_{2.5}$ exceeds air quality standards in the project area, as the DEIR acknowledges.[130] Refinery emissions dominate PM exposures locally, and a statewide analysis of PM as a "GHG co-pollutant" found elevated, localized, and disparate health risks associated with refinery PM emissions.[131] The DEIR does not analyze PM emissions from the project crude switch or propose any additional abatement to address them. However, based on the emission factor Phillips reported for 100% natural gas boiler firing,[132] and the energy increment discussed above (≈2.75 GJ/m^3), the project crude switch could increase SFR emissions of $PM_{2.5}$ by an amount much greater than the significance threshold given in the DEIR.[133]

70. Cumulative impacts of the project with other projects that create long-term commitments to future emissions have the potential to result in failure to achieve the cut in emissions that will be necessary before 2050 to avert extreme climate disruption.[134] Indeed, substantial evidence indicates that stabilizing climate at a societally sustainable greenhouse impact level will require leaving approximately half of current fossil energy reserves underground.[134] Among other important implications of this evidence, it argues

[129] See Karras, 2010; Pastor et al., 2010.
[130] DEIR at 4.3-4, 4.3-5, 4.3-6.
[131] Pastor et al., 2010.
[132] See Air Permit Application at 10, 11 (0.0075 lb $PM_{2.5}$ per MMBtu, which is 3.42 grams/GJ).
[133] Potential emission increment is ≈9.4 g/m^3 crude refined (2.75 GJ/m^3 • 3.42 g/GJ as $PM_{2.5}$) or ≈65.4 tonnes/yr at SFR's 120,000 b/d (6.96 million m^3/yr) capacity. Even one fourth of this increment (≈16 tonnes/yr) exceeds the DEIR's $PM_{2.5}$ significance threshold (10 tons/yr). Other refinery fuel mix scenarios also result in $PM_{2.5}$ estimates exceeding this threshold.
[134] See Davis et al., 2010; Hoffert, 2010; Meinshausen et al., 2009; Allen et al., 2009.

for limiting impacts by choosing to use the least hazardous and least polluting portion of the remaining petroleum resource in the interim.

71. The County could consider a measure that results in using SFR hydrocracking to meet the project's LPG objective without relying on coking a low-quality crude slate. Hydrocracking can be operated to "swing" between product slates, allowing diesel or gasoline or LPG to be its main output, and unlike coking, hydrocracking treats (cleans) its products.[135] Making project LPG from SFR's existing hydrocracking while retaining the project's coker fuel gas hydrotreating is technically feasible and could meet all project objectives stated in the DEIR while avoiding impacts of its potential crude switch. However, increasing LPG output from SFR hydrocracking will limit its gasoline or diesel output,[135] while coker-based LPG production will not—and the proposed project would thereby further boost profits from total light liquids production. In fact, this is one of the reasons the project as proposed would lock the refinery into a denser, more contaminated crude slate. To support this feasible measure, the County could find that boosting profits in a way that makes the project unable to achieve its stated objectives to reduce emissions or to reduce the likelihood of flaring events is not a stated objective of the project.

72. The County also could consider other measures that may lessen impacts from the project's crude switch. However, many different measures may need to be developed to address the myriad potential impacts from refining denser, more contaminated crude. In addition, the relative efficacy of such measures to lessen these impacts cannot, in many cases, be known until the data and analysis that the DEIR could and should have provided to better estimate the scale or severity of these impacts is available for review.

73. On 13 June 2013 the Refinery Action Collaborative, a labor-community collaborative focused on addressing safety and health concerns shared by refinery workers and residents in the Bay Area, submitted to BAAQMD a "recommendation to ensure prevention of feedstock-related emissions increase" that reads in relevant part:

> To prevent new harm from feedstock-related emission increases, each refinery would be required to monitor and report its oil feedstock, and any proposed equipment change related to enabling a change in feedstock quantity or quality. Any proposed change in equipment related to enabling the refining of more oil, lower quality oil, or both, or any actual worsening of oil quality or increase in total oil throughput or both, would trigger a requirement to demonstrate that:

[135] See Robinson and Dolbear, 2007.

- the change in oil quantity, quality, or both (of the blend, of "slate" of oils refined) will not increase incident emission risk;[††]
- the change in oil quantity, quality, or both will not increase routine emissions of any pollutant; *and*
- the change in oil quantity, quality, or both will not use up any emission reduction measure that is needed to reduce the refinery's ongoing emission of any pollutant that currently causes or contributes to air quality or environmental health harm.

Refiners would bear the burden of making each of these demonstrations. The Air District would bear the burden of ensuring transparent reporting and third-party verification through an independent community/worker oversight board that selects and oversees experts. Refiners would bear the burden of funding this independent verification (the independent oversight board and the experts it selects).

Non reporting consequences: Non reporting must not be allowed to defeat prevention. Equipment changes enabling the refining of more oil, lower quality oil, or both that are not reported before installation (1) cannot be considered in a feasibility analysis as a reason for failure to return to baseline emissions, (2) trigger all required demonstrations retroactively, and (3) require refiner-financed Air District monitoring in place of self-monitoring.

[††] *We anticipate that this would be demonstrated through a Process Hazard Analysis or similar documented, verifiable analysis.*[136]

74. The foregoing recommendation[136] is the first specific blueprint for action to evaluate and prevent environmental health and safety impacts from refining lower quality oil that was developed jointly by refinery worker- and community-based organizations. This jointly-developed proposal could thus be considered a critically important step toward solving this problem as presented by the subject project, as well as many other refinery projects regionally and nationwide. Although the BAAQMD is considering this recommendation in the context of a proposed regional air quality rule that could address emissions from refining lower quality oil specifically, at present no such requirement is in place. Importantly, the recommendation describes in significant detail a comprehensive approach to data reporting, evaluation, catastrophic hazard prevention, and emission impact prevention problems presented by this project's potential crude switch. See paragraphs 12–23, 56–72. The County could consider this recommended approach as it completes its analysis, public review process, and decisions regarding the project.

[136] Refinery Action Collaborative, June 2013. Members include the Asian Pacific Environmental Network; BlueGreen Alliance; Communities for a Better Environment; Labor Occupational Health Program at U.C. Berkeley; the Natural Resources Defense Council; United Steelworkers International Union; United Steelworkers Local 5, and United Steelworkers Local 326.

Conclusions

75. Catastrophic failure hazard associated with pressurized storage of propane and butane that would be produced and stored without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR presented an incomplete analysis of this impact, did not identify it as significant, and rejected the consideration required by safety policy of a feasible measure to avoid this impact.

76. Catastrophic failure hazard associated with greater amounts of corrosive, toxic, and flammable materials under high heat and pressure that would be caused by the processing of lower quality oil without adequate safeguards as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure to avoid this impact appears feasible.

77. Acute exposures to air pollutants emitted by flaring to control upsets caused by the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

78. Acute exposures to air pollutants emitted by flaring associated with feeding fuel gases that have lower heat content to equipment designed to burn fuel gases that have higher heat content as a result of the project *may* be considered a significant potential impact—when data the DEIR did not include are reported and reviewed. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although such measures are feasible.

79. Exposures to localized air pollution from continuous emissions of fine particulate matter caused by increased fuel combustion associated with the processing of lower quality oil as a result of the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

80. Sulfur dioxide (SO_2) emissions could increase, instead of decreasing as the DEIR claims, if “emission reduction credits” resulting from the project are overestimated, and this *may* be considered a significant potential impact—when data the DEIR did not

include are reported and reviewed. The DEIR did not disclose these credits for a future emissions increase that could overwhelm the claimed emissions reduction from another part of the project. It did not analyze that emissions reduction claim against these credits to check on whether the credits are overestimated and could thus result in a net emissions increase. It did not consider any measure to lessen or avoid this potential impact, although a measure that could avoid this impact appears feasible.

81. Destruction of aquatic life and San Francisco Bay-Delta habitat caused by the expansion and continued operation of an outdated once-through cooling system as a result of the project should be considered a significant potential impact. The DEIR did not disclose state efforts that could replace the cooling system—thereby avoiding this impact—or that the project would conflict with and foreclose those efforts. The DEIR presented an incomplete, erroneous, and misleading discussion of this impact, did not identify it as significant, and did not consider any measure to lessen or avoid this impact.

82. Greenhouse gas emissions caused by burning propane and butane that would be produced and sent out of the refinery for this purpose as a result of the project should be considered a significant potential impact. The DEIR presented an erroneous analysis of these emissions, did not identify this impact, and did not consider any measure to lessen or avoid it, although such measures appear feasible.

83. Greenhouse gas emissions caused by increased refinery fuel combustion associated with the processing of lower quality oil resulting from the project should be considered a significant potential impact. The DEIR did not analyze or identify this impact, and did not consider any measure to lessen or avoid it, although a measure that could avoid this impact appears feasible.

84. The June 2013 DEIR did not include the information necessary to understand and evaluate the environmental implications of the project. It did not describe the duration, setting, geographic or processing scope, feedstock, operation, or potential environmental effects of the project accurately or, in many cases, did not describe them at all. These informational deficiencies are so profound, and the revisions needed to cure them so extensive, that full independent review of a comprehensively revised draft would be necessary before public decisions could be based with confidence on this project's environmental review.

85. I have given my opinions on these matters based on my knowledge, experience and expertise and the data, information and analysis discussed in this report.

I declare under penalty of perjury that the foregoing is true of my own knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

Executed this _____ day of September 2013 at Oakland, California

____
Greg Karras

Attachments List

Descriptor	***Attachment***
Abella and Bergerson, 2012	Abella and Bergerson, 2012. Model to investigate energy and greenhouse gas emission implications of refining petroleum: impacts of crude quality and refinery configuration. *Env. Sci. Technol.* DOI: 10.1021/es30186821.
AICE, 1989 (excerpts)	American Institute of Chemical Engineers, Center for Chemical Process Safety, 1989. Guidelines for process equipment reliability data, with data tables. (Excerpts: pp. 183, 205).
Air Permit App.	ERM, 2013. Rodeo Propane Recovery Project BAAQMD Authority to Construct and Significant Revision to Major Facility Review Permit Application, Rodeo Refinery. February 2013.
Air Permit App. Atts 4 and 7	ERM, 2013 (Permit Application). Attachment A-4. Fugitive component TAC emissions; and Attachment A-7. Daily U233 fuel gas data.
Air Permit Correspondence	Correspondence regarding incomplete permit application for the project including: 30 April 2013 letter to Brian Lusher, Bay Area Air Quality Management District, from Don Bristol, Phillips 66 San Francisco Refinery (4/30/13 Phillips letter); 6/28/13 Phillips letter; 3/1/13 Phillips letter; 1 March 2013 letter to Brent Eastep, Phillips 66 Rodeo Refinery, from Brian Lusher, Bay Area Air Quality Management District (3/1/13 BAAQMD letter); 3/21/13 BAAQMD letter; 7/18/13 BAAQMD letter.
Allen et al., 2009	Allen et al., 2009. Warming caused by cumulative carbon emissions towards the trillionth tonne. *Nature* 458: 1163–1166.
API, 2009	American Petroleum Institute, 2009. Guidelines for avoiding sulfidation (sulfidic) corrosion failures in oil refineries. API Recommended Practice 939–C, First Edition.
BAAQMD, 2006	Staff Report, Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries. Bay Area Air Quality Management District. 3 March 2006.
BAAQMD, 2009	Bay Area Air Quality Management District 18 September 2009 response to request for facility information by CBE (listing of Chevron Richmond Refinery dates of first operation by equipment source number; includes summary table by CBE).
BAAQMD, 2011	Major Facility Review Permit, Chevron Products Company, Facility #A0010. Bay Area Air Quality Management District. 11

August 2011.

BAAQMD, 2013	Major Facility Review Permit, Phillips 66–San Francisco Refinery, Facility #A0016. Bay Area Air Quality Management District. 4 March 2013.
Brandt, 2012	Brandt, 2012. Variability and uncertainty in life cycle assessment models for greenhouse gas emissions from Canadian oil sands production. *Env. Sci. Technol.* 46: 1253–1261.
Bredeson et al., 2010	Bredeson et al., 2010. Factors driving refinery CO_2 intensity, with allocation into products. *Int. J. Life Cycle Assess.* 15: 817–826.
CARB, 2013	Mandatory GHG Reporting Data. Emissions reported for calendar years 2009, 2010, 2011. California Air Resources Board. (Dnldd 28 August 2013: https://ghgreport.arb.ca.gov/eats/carb).
CBE, 1994	CBE, 1994. Dirty crude: The first oil industry-wide analysis of selenium discharge trends impacting San Francisco Bay. CBE Report No. 94–1. March 1994.
CBE, 2006	CBE, 2006. Analysis of Potrero Unit 3 entrainment impact evidence. March 2006.
CCHMP–Phillips 071113	Letter to Jim Ferris, Phillips 66 San Francisco Refinery, from Michael Dossey, Contra Costa Health Services Hazardous Materials Program. 11 July 2013.
Chevron R2-2011-0049	NPDES Permit No. CA0005134. Chevron Richmond Refinery. Issued in 2011.
City of Richmond, 2008	Chevron Energy and Hydrogen Renewal Project Final Environmental Impact Report SCH #2005072117 Volume 3–Responses to Comments. January 2008.
Crude Assays	Compilation of publicly reported crude oil assay reports.
CSB, 2005	CSB, 2005. Investigation Report: Refinery Explosion and Fire (15 Killed, 180 Injured); BP Texas City, Texas, March 23, 2005. Report No. 2005–04-I-TX. U.S. Chemical Safety and Hazard Investigation Board. March 2007.
CSB, 2013	CSB, 2005. Interim Investigation Report: Chevron Richmond Refinery Fire; Chevron Richmond Refinery, Richmond, California, August 6, 2012. U.S. Chemical Safety and Hazard Investigation Board. April 2013.
CV and Publications	Curriculum vitae and publications list
Davis et al., 2010	Davis et al., 2009. Future CO_2 emissions and climate change from existing energy infrastructure. *Science* 329: 1330–1333.

DOE COA 2013	DOE, 2013. Crude Oil Analysis Database. U.S. Department of Energy. Data table in Excel. (www.netl.doe.gov/technologies/oil-gas/Software/database.html). Downloaded 8 August 2013.
DOE, 2002.	DOE, 2002. Strategic Petroleum Reserve Crude Oil Assay Manual, 2nd Edition, Revision 2. U.S. Department of Energy. Revised November 2002.
Dolbear AG Summary	Email from Rose Fua, California Deputy Attorney General summarizing and quoting from a review by Dr. Geoff Dolbear regarding the Chevron Richmond refinery (other Bay Area data were reviewed as well). Forwarded to CBE 16 July 2008.
EIA Imports Analysis	Tables of data for foreign oils processed by the San Francisco Refinery reported by the U.S. Energy Information Administration (www.eia.gov/petroleum/imports/comanylevel/archive)
EIA Ref. Cap. 2013	U.S. Energy Information Administration, 2013. Refinery Capacity Data by Individual Refinery as of January 1, 2013 (www.eia.gov/petroleum/data). Downloaded 26 August 2013.
EIA Refinery Yield	U.S. Energy Information Administration, 2013. U.S. Refinery Yield. (www.eia.gov/dnav/pet/pet_pnp_pct_dc_nus_pct_m.htm)
ERCB st98–2009	ERCB, 2009. Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009–2018. Report ST98–2009. Energy Resources Conservation Board, Alberta, Canada. June 2009.
ERM & BAAQMD, 2012	CEQA Initial Study: Marine Terminal Offload Limit Revision Project, Phillips 66 Refinery, Rodeo, California, BAAQMD Permit Application 22904. Bay Area Air Quality Management District (prepared by ERM). December 2012.
Flare Causal Analysis excerpts	Phillips 66, various dates. Determination and Reporting of Cause reports pursuant to BAAQMD Rule 12-12 §406 for flaring initiating on 3/16/12, 4/25/12, 5/23/12, 5/31/12, 8/27/12.
Flaring Hot Spots	Karras and Hernandez, 2005. Flaring hot spots: Assessment of episodic air pollution associated with oil refinery flaring using sulfur as a tracer. A CBE Report. July 2005.
Flaring Prevention Measures	Karras et al., 2007. Flaring Prevention Measures. A CBE Report. April 2007.
Fox, 2013	Fox, 2013. Comments on Initial Study/Mitigated Negative Declaration for the Valero Crude by Rail Project, Benicia, California, Use Permit Application 12PLN–00063. July 2013.
Goodman, 2013	Goodman and Rowan, 2013. Comments of the Goodman Group, Ltd., on Initial Study/Mitigated Negative Declaration, Valero

	Crude by Rail Project, Benicia, California, Use Permit Application 12PLN-00063.
Hoffert, 2010	Hoffert, 2009. Farewell to fossil fuels? *Science* 329: 1292–1294.
Karras, 2008	Karras, 2008. Chevron Renewal Project, SCH #2005072117, City #1101974 Agenda Report, Consolidated EIR and Staff-recommended EIR and Conditional Use conditions and findings related to oil quality cap; expert report.
Karras, 2010	Karras, 2010. Combustion emissions from refining lower quality oil: What is the global warming potential? *Env. Sci. Technol.* 44(24): 9584–9589.
Karras, 2013	Testimony of Greg Karras, Senior Scientist, CBE, before the U.S. Chemical Safety and Hazard Investigation Board (CSB), 19 April 2013, Memorial Auditorium, Richmond, CA.
LOHP, 2013	Wilson, 2013. Refinery Safety in California: Labor, community and fire agency views. Summary report prepared for the Office of Governor Jerry Brown, Interagency Task Force on Refinery Safety, by the Labor Occupational Health Program at U.C. Berkeley. Revised 4 June 2013.
Meinshausen et al., 2009	Greenhouse-gas emission targets for limiting global warming to 2 ºC. *Nature* 458: 1158–1162.
Meyer et al., 2007	Meyer, 2007. Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey Open-File Report 2007-1084.
Meyers, 1986	Handbook of petroleum refining processes. Meyers, Robert A., ed. ISBN 0-07-041763-6. McGraw-Hill. 1986.
NPDES Permit R2-1985-029	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1985.
NPDES Permit R2-1989-002	NPDES Permit No. CA0005053. Union Oil Co. San Francisco Refinery, Rodeo. Issued in 1989.
NPDES Permit R2-2000-015	NPDES Permit No. CA0005053. Tosco Corp. San Francisco Refinery at Rodeo. Issued in 2000.
NPDES Permit R2-2005-0030	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued 2005.
NPDES Permit R2-2011-0027	NPDES Permit No. CA0005053. ConocoPhillips Corp. San Francisco Refinery at Rodeo. Issued in 2011.
NPDES Permit R3-2007-0002	NPDES Permit No. CA0000051. ConocoPhillips Corp. Santa Maria Refinery. Issued in 2007.

Oil & Gas Journal, 2012	Koottungal, 2012. 2012 Worldwide Refining Survey. *Oil & Gas Journal.* 3 December 2012 (All figures are as of January 1, 2013).
Pastor et al., 2010	Pastor et al., 2020. *Minding the climate gap: What's at stake if California's climate law isn't done right and right away.* USC Program for Environmental and Regional Equity: Los Angeles, CA. http://college.usc.edu/pere/publications.
Phillips Cooling Tower	*Cooling Tower Replacement Feasibility Evaluation, Order R2-2011-0027; Provision VI.C.2.f., Phillips 66 San Francisco Refinery at Rodeo.* Submitted by Don Bristol, Superintendent, Environmental Services, Phillips 66 San Francisco Refinery, no 30 September 2013. (13-page report)
Phillips Intake Rpt.	*Waste Water Annual Report for 2012, Phillips 66, San Francisco Refinery.*
Phillips Thermal ext. 1	8 August 2012 letter from Don Bristol, Phillips 66 San Francisco Refinery, to Regional Water Quality Control Board, San Francisco Bay Region, regarding: *Phase 2 Thermal Plume Study Final Report, NPDES Order #R2-2011-0027, Provision VIC2d; Task 3 Request for Due Date Extension.*
Phillips Thermal ext. 2	4 September 2012 letter from Bruce Wolfe, Regional Water Quality Control Board, San Francisco Bay Region, to Don Bristol, Phillips 66 San Francisco Refinery, regarding: *Phase 2 Thermal Plume Study Final Report Compliance Date Extension.*
Phillips, 2012a	Phillips 66, 2012. *Propane Recovery Project Overview, August 13 2012, Phillips 66 San Francisco Refinery.* Submitted to BAAQMD. Provided by BAAQMD to CBE (slides presentation).
Phillips, 2012b	Phillips 66, 2012. *Rodeo Propane Recovery Project, Project Description.* August 2012. Submitted to BAAQMD. Provided by BAAQMD to CBE (32-page document).
Refinery Action Collaborative, June 2013	Letter to Jack Broadbent, Bay Area Air Quality Management District, from the Refinery Action Collaborative regarding: *Bay Area Air Quality Management District Proposed Regulation 12, Rule 15; March 2013 Preliminary Draft Petroleum Refining Emissions Tracking Rule.* 13 June 2013.
Regional Monitoring Program	Regional Monitoring Program (RMP) Results. San Francisco Estuary Institute. Data tables report generated by the RMP Web Query (www.sfei.org/mp/mp_data_access.html). Report generated 17 August 2013.
Robinson and Dolbear, 2007	Robinson and Dolbear, 2007. Commercial hydrotreating and hydrocracking. In *Hydroprocessing of heavy oils and residua;*

	Ancheyta, J., Speight, J.G., Eds.; CRC Press, Taylor & Francis Group: Boca Raton, FL. Vol. 117: 281-311.
Shell R2-2012-0052	NPDES Permit No. CA0005789. Shell Martinez Refinery. Issued in 2012.
Sheridan, 2006.	*California Crude Oil Production and Imports.* Staff Paper. CEC-600-2006-006. Margaret Sheridan, Fossil Fuels Office, California Energy Commission. April 2006.
SMF EIR 2012 Excerpts.	*Phillip 66 Santa Maria Refinery Throughput Increase Project Final Environmental Impact Report.* SCH #20081010111. Prepared for San Luis Obispo County Department of Building and Planning by Marine Research Specialists (MRS). October 2012. Excerpt includes cover page, table of contents, and project description (chapter 2.0).
Speight, 1991	Speight, 1991. *The chemistry and technology of petroleum,* 2nd ed.; Heinemann, H., Ed.; Marcel Dekker: New York, Chemical Industries, Vol. *44.*
State Lands, 1995.	*Final Environmental Impact Report for Consideration of a New Lease for the Operation of a Crude Oil and Petroleum Product Marine Terminal on State Tide and Submerged Lands at Unocal's San Francisco Refinery, Oleum, Contra Costa County.* SCH # 91053082. Prepared for State Lands Commission by Chambers Group, Inc. February 1995.
Subra, 2008	*Chevron Energy and Hydrogen Renewal Project.* Expert report prepared for the Asian Pacific Environmental Network by Wilma Subra, Subra Company, New Iberia, LA. May 2008.
SWRCB, 2010	*Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.* California State Water Resources Control Board. October 2010.
Tesoro R2-2010-0084	NPDES Permit No. CA0004961. Tesoro Golden Eagle Refinery. Issued in 2010.
UCS, 2011	UCS, 2011. *Oil Refinery CO_2 Performance Measurement.* Union of Concerned Scientists: Berkeley, CA. Technical analysis prepared for UCS by G. Karras, Communities for a Better Environment. September 2011.
Valero R2-2009-0079	NPDES Permit No. CA0005550. Valero Benicia Refinery. Issued in 2009.
Wilhelm et al., 2007	Wilhelm et al., 2007. Mercury in crude oil processed in the United States (2004). *Env. Sci. Technol.* 41(13): 4509–4514.